Consideration of Comments on Initial Ballot of PRC-005-2 – Protection System Maintenance

The Protection System Maintenance Standard Drafting Team (PSM SDT) thanks all those who participated in the initial ballot for the proposed revisions to PRC-005 - Protection System Maintenance.

- 87.85% quorum
- 39.35 % weighted segment approval

All comments received with affirmative and negative ballots are included in this report.

All balloters are advised to review the comments and responses in this report as an aid in determining how to participate in the recirculation ballot.

Both a clean and a redline version of the standard that shows the conforming revisions are posted at the following site:

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

Many commenters objected to the establishment of maximum allowable intervals and offered comments on virtually every individual activity and interval within the Tables. The SDT responded that "FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities." In an effort to provide more clarity, the SDT also completely revised the Tables of maximum maintenance intervals/minimum maintenance activities, and made numerous other changes throughout the draft Standard. Many commenters also indicated a preference for much of the information that is currently contained within the reference documents to be included within the Standard itself. The SDT responded by including the definitions of terms exclusively used within this standard, specifically "component type", "component", "segment", "maintenance correctable issue", and "countable event", , within the body of the standard. Numerous comments were also offered, proposing that the VSLs allow for some amount of non-compliance with the Standard before incurring a violation. The SDT responded by stating that: "The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation."

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Segment:	1
Organization:	International Transmission Company Holdings Corp
Member:	Michael Moltane
Comment:	While voting affirmative due to the improvements over the existing standards, we do have the following comments. We hope the Standards Team can take these comments and suggested improvements into account although we did not get our comments in during the official comment period due to confusion over the overlapping comment/ballot period. The following are ITC Holdings comments corresponding the questions on the comment form: Regarding Question #1: ITC Holdings does not agree with the 6 year time interval for functional testing of the control and trip circuits. 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. A scheme that is 100% microprocessor relays except for 1 electromechanical AR or SG relay would be forced to a 6 year interval instead of a 12 year interval. This seems unreasonable for schemes that are otherwise identical. Comments on Question #4: ITC Holdings agrees with the measure and data retention requirements assuming that the requirements only apply to test data after the effective date of the approved standard. Comments on Question #7: It should clearly state in the definition or elsewhere in the standard that automatic ground switches intended to protect the BES are to be considered interrupting devices. This is stated in the Supplemental Reference but the Supplemental Reference is not part of the standard. Please consider splitting the first row in Table 1a (Protective Relays) into 2 separate rows, one for relays other than microprocessor and the other for microprocessor relays. • Include the sentence “Verify that settings are as specified.” In both rows to be clear that this applies to both categories. (The following is intended to be helpful information only not to be included in the comments) The following provides a clue as to what Time Horizon means: From: http://www.nerc.com/docs/pc/ris/Order_890-A_pro_forma_Attachment_C.doc (1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its

	scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon); See Definition at: http://www.nerc.com/files/Time_Horizons.pdf Copy below: Time Horizons Time Horizons are used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time. When establishing a time horizon for each requirement, the following criteria should be used: 1. Long-term Planning — a planning horizon of one year or longer. 2. Operations Planning — operating and resource plans from day-ahead up to and including seasonal. 3. Same-day Operations — routine actions required within the timeframe of a day, but not real-time. 4. Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system. 5. Operations Assessment — follow-up evaluations and reporting of real time operations.
Response:	Thank you for your comment. Question #1 - The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The SDT believes that mechanical solenoid-operated devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. Question #4 – The SDT believes that entities cannot be expected to initially have data for requirements that did not previously exist. Question #7 – From a mandatory perspective, this is dependent on the regional BES definitions and on what those definitions may describe to be “transmission Protection Systems.” • The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. Time Horizon – Thank you for your input.
Segment:	5
Organization:	U.S. Bureau of Reclamation
Member:	Martin Bauer

Comment:	1. There is no reliability based justification to alter the standards to require practices of a subset of entities as allowable intervals. It is incredible that the standard would suppose that requiring the use of weighted average practice of some subset of all entities could reasonable. The purpose of a reliability standard is to ensure the reliability of the BES. There is no indication that the existing standard has posed a threat to the reliability of the BES. There is no data which indicates that the BES reliability is impacted because of certain maintenance practices. The SDT has chosen an approach which has statistical merit and is good information for entities to consider in reviewing their maintenance program. To force an entity to enhance its maintenance program because some subsets of entities have a different program is contrary to the purpose authorized by the Energy Policy Act of 2005. The variables of each entity faces when developing their maintenance practice intervals cannot be calculated through statistical analysis. To presume that the end result (the interval itself) can be applied to other entities ignores the sound decisions made internally to each entity that results in final interval. The standard should return to addressing real reliability impacts as required by law. The desire to improve maintenance programs offers a unique problem to the FERC and regulatory world. The knee jerk reaction is to define a "universal" interval based on some statistical method. What happens if the solution is bad, who will accept the consequences that narrow prescription was wrong and the interval caused a reliability impact. It would no longer be the Entity. The standard does not make such an allowance. History is replete with examples of this type of micro managing. Rather than fall into the same trap, and suffer the consequences of the unknown, it is suggested to allow Entities to optimize their programs to ensure reliability of the BES. If the NERC wants to create a reliability based standard that addresses reliability impacts, the SDT is encouraged to create a standard of "disallowed" practices. These would be practices which have a demonstrated impact on reliability. The SDT should spend to analyzing maintenance practices which have a known impact on reliability (as evidenced by disturbance reports) and develop requirements which disallow such practices or range of practices. In addition, if it is shown that an event in which BES reliability was impacted by the utilities PSMP (as evidenced by disturbance reports), the utility would be required to submit to the RRO a corrective action plan which addresses how the PSMP will be revised and when compliance with that PSMP is to be achieved. 2. The intervals prescription for performance based PSMP virtually eliminates the capability of smaller utilities that do not have a large equipment database to justify a performance based system that may be sound based on their experience. This overly prescriptive approach should be eliminated and return to allowing utilities to justify their programs. 3. The Time Horizons are too narrow for the implementation of the standard as written. The SDT appears to

	have not accounted for the data analysis associated with performance based systems. The data collection, analysis, and subsequent decisions associated development of a maintenance program and its justification do not occur overnight especially with larger utilities. In addition, this new standard will require complete rewrite of an entities internal maintenance programs. The internal processes associated with these vary based on the size of the entity and its organizational structure. 4. Since this standard is so invasive into the internal decisions concerning maintenance, the standard should allow at least 18 months for entities to rewrite their internal maintenance programs to meet the program development requirements and 18 months to train the staff in the new program, incorporate the program into the entities compliance processes, and to implement the new program.
Response:	Thank you for your comment. 1. FERC directed the SDT to establish maximum time intervals between maintenance activities. The SDT recognized that different types of equipment, different generations of equipment, different failure modes of equipment, and different versions of time-based maintenance had to be considered. The SDT agrees with the commenter that the Standard allows statistical analysis, and performance-based maintenance allows an entity to create time intervals that could exceed any "weighted-averages" time-based intervals. The Supplementary Reference adds a Section 9 to show how an entity can create a performance-based maintenance interval. 2. FERC directed the SDT to establish maximum time intervals between maintenance activities. Smaller entities may aggregate their component populations with other entities having similar programs – see Section 9 of the Supplementary Reference document and FAQ IV.3.A. Entities are not required to use performance-based PSMPs; this option is made available to entities who wish to use it. 3. Your comment appears to address the Implementation Plan, not Time Horizons. The Implementation Plan for Requirement R1 has been extended from three months to twelve months. For performance-based programs, Attachment A specifies that there must first be acceptable results, and that a time-based program (per the Tables) must be used until then. See FAQ IV.3.B. 4. The Implementation Plan for Requirement R1 has been extended from three months to twelve months.
Segment:	5
Organization:	South Mississippi Electric Power Association
Member:	Jerry W Johnson
Comment:	The proposed Standard is overly prescriptive and too complex to be practically implemented. An entity

	making a good faith effort to comply will have to navigate through the complexities and nuances, as illustrated by the extensive set of documents the SDT has provided in an attempt to explain all the requirements and nuances. The need for an extensive “Supplementary Reference Document” and an extensive “Frequently Asked Questions Document”, in addition to 13 pages of tables and an attachment in the standard itself, illustrate that the proposal is too prescriptive and complex for most entities to practically implement. 1. The descriptions for the "type of protection system components" do not appear to be consistent between Tables, 1a, 1b and 1c. 2. The maximum maintenance interval for a lead-acid vented battery is listed at 6 calendar years for performing a capacity test. This type of test has been proven to reduce battery life and an interval of 10 to 12 years would be better. 3. The maximum maintenance interval for "Station DC supply" was set at 3 months. This is too short of a period and 6 months would be better. 4. The control and trip circuits associated with UVLS and UFLS do not require tripping of the breakers but all other protection systems require tripping of the breakers, this appears to be inconsistent? 5. Digital relays have electromagnetic output relays. Do they fall into the electromechanical trip or solid state trip? 6. Need for clarification: The standard indicates that only voltage and current signals need to be verified. Does this mean that voltage and current transformers do not need to be tested by applying a primary signal and verifying the secondary output? 7. With regard to DPs who own transmission Protection Systems, the standard is still very unclear on when a DP owns a transmission Protection System. Many DPs own equipment that is included within the definition of a Protection System; however, ownership of such equipment does not necessarily translate directly into a transmission Protection System under the compliance obligations of this standard. DPs need to know if this standard applies to them and right now, there is no certain way of determining that from within this language or previous versions of this standard.

	8. The phrase "Verify Battery cell-to-cell connection resistance" has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting "unit-to-unit" wherever "cell-to-cell" is used in the table now. 9. The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don't match those in level 1. Which activities shall we use? 10. Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent.
Response:	Thank you for your comments. FERC Order 693 and the approved SAR assign the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 2. The SDT disagrees. 3. The SDT disagrees. 4. Your observation is correct. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping distribution system elements 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. 6. Your observation is correct. 7. Your concern seems to be primarily related to the applicable regional BES definition.

	8. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. "Cell" has been replaced with "cell/unit" to address this concern. 9. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 10. The SDT disagrees. You should complete the activities within the intervals specified.
Segment:	5
Organization:	RRI Energy
Member:	Thomas J. Bradish
Comment:	For PRC-005-2, while there is nothing inherently wrong with the requirements, RRI voted affirmative with concern. Our concern is we believe that rather than fixing the issues that caused the 2003 blackout, there is a continual drift to extensive micro-management to take control of every aspect of the entire industry through regulation in the name of reliability. I believe the documentation required to demonstrate 100% compliance to this standard will be a serious challenge to achieve uniformly for so many components across a widely dispersed fleet, especially in the punitive, zero-tolerance compliance world that presently exists. It only takes the things we are in short supply: time, money, and people. It will drive industry to better systems and performance, but there will be a painful price, especially on the development side. An example of the impact of this standard: station power plant batteries are sized to carry large DC loads with the protection system as only a small fraction of the load profile. Rather than performing a risk assessment for station with low capacity factors (for example RRI has a two unit station that had an average capacity factor in 2009 of 1.72%) after the battery slightly crosses over its degradation threshold, there will be no choice but an immediate and expensive replacement. This type of requirement will push many units into pre-mature retirement or mothballing.
Response:	Thank you for your comment.
Segment:	3
Organization:	Tampa Electric Co.
Member:	Ronald L Donahey
Comment:	The level of DC circuit testing required every time the relay is tested represents potentially a negative impact to reliability given the complicated control circuitry in an energized station. Even though you take out an element out of service, the DC control circuits are often interconnected for functions such as breaker failure,

	bus and transformer lockouts, etc. This level of testing needs to be done when initial construction but this increase in testing is not justifiable given the reliability risk and cost. TEC's record for misoperations do to circuitry failure does not support this need.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The SDT believes that mechanical solenoid-operated devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.
Segment:	5
Organization:	Salt River Project
Member:	Glen Reeves
Comment:	SRP believes the requirements of the Standard are confusing and may be problematic in determining compliance. We also believe the required functional testing of the breaker trip coil may potentially increase maintenance outages of circuit breakers. In most cases, circuit breaker maintenance outages can be coordinated such that Protection System maintenance and testing can be done simultaneously. However, in some cases this may not be possible. Outages of any BES facility whether planned or unplanned can impact system reliability. SRP suggests that trip coil monitoring devices be included as an acceptable means of ensuring the trip coil is functioning properly. This will help to avoid unnecessary outages.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The SDT believes that mechanical solenoid-operated devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.
Segment:	1, 3, 4, 6
Organization:	Seattle City Light
Member:	Pawel Krupa, Dana Wheelock, Hao Li, Dennis Sismaet
Comment:	Functional testing is impractical.

Response:	Thank you for your comment. Functional testing is not the only means of completing the required maintenance, although it may be the most practical.
Segment:	3
Organization:	JEA
Member:	Garry Baker
Comment:	JEA does not believe the standard adequately addresses issues like component, FAQ, etc as identified below: 1. R1.1 Identify all Protections System components. What is meant by Protection System component? Is a component a wire, contact, device, etc. A list of components as intended by the SDT would be illustrative in understanding the SDT's intent of what a component includes. 2. Are the FAQ and Supplemental Reference going to be adopted as part of this standard? These documents contain information that is critical to the proper understanding and interpretation of the standard, thus either the standard needs to be rewritten to include this information, or the FAQ and Supplemental Reference need to be adopted as part of this standard. Any inconsistencies between the FAQ and the standard, as written, would need to be corrected. 3. The maximum maintenance interval for a lead-acid vented battery is listed as 6 calendar years for performing a capacity test. This type of test has been proven to reduce battery life and a longer capacity test interval of 10 to 12 years would be better, allowing for longer battery life. 4. The implementation period for R1.1 of 3 months is too short and should be extended to one calendar year; of course this is dependent on the complexity of items listed as part of the definition of "Protection System component."
Response:	Thank you for your comment. 1. A definition of "Component" has been added to the draft Standard. The SDT's intent is that this definition will be used only in PRC-005-2, and thus will remain with the Standard when approved, rather than being relocated to the Glossary of Terms. 2. These documents provide supporting discussion, but are not part of the Standard. The SDT intends that these be posted as Reference Documents, accompanying the Standard.

	3. The SDT disagrees. 4. The Implementation Plan for Requirement R1 has been modified from three months to twelve months.
Segment:	5
Organization:	Public Utility District No. 1 of Lewis County
Member:	Steven Grega
Comment:	1. As written PRC-005-2 does not recognize or accommodate the many type of batteries in use at substations. To accommodate many of the prescribed tests, the batteries would have to be disassembled to conduct the test with little valuable information gained. Suggest wording only saying the batteries should be periodically test to assure that they perform as designed. Let the entities' engineers decide on what is most appropriate for their batteries. 2. Having a standard that requires 100% compliance on 1000's of components is a good way of assuring many violations. Most protective system can function with half the protection in service. Typically most engineers over design and have backup upon backup on critical elements. Suggest standard require a lesser compliance rate; say 90% to 95% during an audit. The elements not in compliance could be followed by a 12 month plan to bring other elements into compliance but the entity at 90% to 95% would still be found compliant. In summary, this proposed standard has gone beyond the reasonably level of regulation by NERC. Therefore, I am voting not to affirm the revision to this standard.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 2. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	3
Organization:	City of Farmington
Member:	Linda R. Jacobson
Comment:	As written, is opens up the PRC-005 standard to Technical Feasibility Exceptions because some batteries are not able to accommodate all of the tests proscribed in the draft standard as explained by Steve Alexanderson in a prior e-mail to the ballot pool. The draft standard would cause NERC to regulate through the standards

	battery testing, DC circuit testing, etc. on distribution elements with no significant improvement to BES reliability, which is beyond the statutory scope of the standards
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. “Cell” has been replaced with “cell/unit” to address this concern. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system.
Segment:	1
Organization:	Pacific Gas and Electric Company
Member:	Chifong L. Thomas
Comment:	The requirements in the latest draft are confusing and at times seem to be in conflict with other requirements. From a compliance and enforcement perspective, this confusion would make the standard difficult to audit. 1. We are concerned over R1.1, where all components must be identified, without a definition for the word component or the granularity specified. While the FAQ gives a definition, and allows for entity latitude in determining the granularity, the FAQ is not part of the standard. We are concerned whether identification is required for every individual component, such as each auxiliary relay, or is it sufficient that the auxiliary relays are included within the scheme that is being tested and documented. Do the auxiliary relays need to be documented within the maintenance database and/or on the actual test reports of schemes being tested? We suggest that the FAQ definitions be included within the standard. 2. We agree with most of the changes from the last draft in Table 1a, 1b and 1c. However, the phrase “Verify Battery cell-to-cell connection resistance” has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting “unit-to-unit” wherever “cell-to-cell” is used in the table now.

	3. The level 1 table regarding Control and trip circuits with electromechanical trip or auxiliary contacts now includes exception for microprocessor relays, but there is no listing for the requirements for microprocessor relays. 4. The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don't match those in level 1. Which activities shall we use? 5. Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing.
Response:	Thank you for your comment. 1. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. "Cell" has been replaced with "cell/unit" to address this concern. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 and 1-5. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
Segment:	5
Organization:	Pacific Gas and Electric Company
Member:	Richard J. Padilla
Comment:	The level of detail of this standard is over the top and currently conflicts with other standards and is open for future conflicts. We recommend that the standard DT evaluate the basic rational for the standard and limit its scope. Some examples are: 1. As written, is opens up the PRC-005 standard to Technical Feasibility Exceptions because some batteries are not able to accommodate all of the tests proscribed in the draft standard as explained by Steve Alexanderson in a prior e-mail to the ballot pool. The draft standard would cause NERC to regulate through the standards battery testing, DC circuit testing, etc. on distribution elements with no significant

	improvement to BES reliability, which is beyond the statutory scope of the standards 2. The standard unreasonably retains the "100% compliance" paradigm for thousands, if not millions of protection system components as written, the standard requires testing of batteries, DC control circuits, etc., of distribution level protection components associated with UFLS and UVLS. UFLS and UVLS are different than protection systems used to clear a fault from the BES. An uncleared fault on the BES can have an Adverse Reliability Impact and hence; the focus on making sure the fault is cleared is important and appropriate. However, a UFLs or UVLS event happens after the fault is cleared and is an inexact science of trying to automatically restore supply and demand balance (UFLS) or restore voltages (UVLS) to acceptable levels. If a few UFLS or UVLS relays fail to operate out of potentially thousands of relays with the same function, there is no significant impact to the function of UFLS or UVLS. Hence, there is no corresponding need to focus on every little aspect of the UFLS or UVLS systems. Therefore, the only component of UFLS or UVLS that ought to be focused on in the new PRF-005 standard is the UFLS or UVLS relay itself and not distribution class equipment such as batteries, DC control circuitry, etc., and these latter ought to be removed from the standard. 3. In addition, most distribution circuit are radial without substation arrangements that would allow functional testing without putting customers out of service while the testing was underway, or at least without momentary outages while customers were switched from one circuit to another. Therefore, as written, we would be sacrificing customer service for a negligible impact on BES reliability
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. “Cell” has been replaced with “cell/unit” to address this concern. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system. 2. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. 3. Functional testing is not the only means of completing the required maintenance, although it may be the most practical.
Segment:	5
Organization:	Indeck Energy Services, Inc.
Member:	Rex A Roehl
Comment:	As discussed at the FERC Technical Conference on Standards Development, the goal of the standards

	program is to avoid or prevent cascading outages--specifically not loss of load. The expansion of this standard deviates significantly from its purpose of maintaining protective systems that affect BES reliability. It doesn't recognize that not all relays affect reliability. If reliability is measured by a Reportable Disturbance, then the threshold varies by control area--largest contingency. The standard should include a process, not unlike the risk based assessment in CIP-002-2 R1, to include as "identified components" only those affecting reliability. All of the various reliability criteria should be considered.
Response:	Thank you for your comment. "BES reliability" is more than simply avoiding "cascading outages" – as illustrated by the approved definition of "Adequate Level of Reliability" as promulgated by the NERC Planning and Operating Committees in response to a directive from FERC, and as described in Section 215 of the Federal Power Act.
Segment:	5
Organization:	Black Hills Corp
Member:	George Tatar
Comment:	1. Draft is confusing & seems to conflict with other requirements. Table 1b Maint. Activities needs to define whether all protection logic or conditions would initiate a relay trip output are required to be simulated & tested to the relay tripping output contact. 2. The Attachment A definition of "common factors" is way too broad to be utilized in defining a grouping of protection system devices.
Response:	Thank you for your comments. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The SDT is not clear whether your concern is about "common factors" as used in the definition of "Segment." See Section 9 of the Supplementary Reference document for a discussion of performance-based maintenance.
Segment:	4
Organization:	Wisconsin Energy Corp.
Member:	Anthony Jankowski
Comment:	1. Table 1a, Protective Relays: Change 1st line to: "Test and calibrate if necessary the relays…"

	Table 1a & 1b, Protective Relays: 3rd line: Change “check the relay inputs…” to “verify the relay inputs…” The term “check” is not defined, whereas “verify” is. Tables 1a & 1b We agree that six / twelve years is an acceptable interval for relay maintenance. Table 1a & 1b, Control & Trip Circuits: The proposed addition to require tripping circuit breakers during Protection System maintenance will require outages and is therefore detrimental to BES reliability and should be removed. – Generating unit protection system maintenance is done during scheduled outages. The high voltage breaker on a generating unit often remains energized to back feed and supply station auxiliaries when the generator is offline. The proposed requirement will increase the amount of equipment requiring an outage for maintenance, and possibly the length of the outage, resulting in significantly more equipment out of service as well as increased costs. This requirement also results in greater maintenance efforts and costs when there are redundant protection system equipment (breaker trip coils, lockout relays, etc), which is contrary to good practice and reliability. – Many of the breakers that We Energies, as the Distribution Provider, trips from its BES protection systems are not owned by We Energies and are owned by a separate transmission company. The trip testing and maintenance of the transmission company may not coincide with our relay maintenance testing program. The standard shall have allowances for the entity to ONLY test or maintain equipment that it OWNS! Table 1a, Station dc supply: – The activity to verify the state of charge of battery cells is too vague, and requires more specific action. We assume that the drafting committee is recommending specific gravity measurements. Specific gravity measurements have not been shown to be an accurate indicator of state of charge. In addition, as shown in the nuclear power industry, there is no established corrective action that is taken based on specific gravity results (eg. Don’t require a test where there is no acceptable corrective action). – The activities to “verify battery continuity” and “check station dc supply voltage” are also vague and need to be more clearly specified what is intended. – The 3 month time interval for battery impedance testing is too frequent. 18 month or annual testing is more appropriate.

	– The 3 calendar year performance or service test is too frequent and will actually remove life from a battery and reduce reliability. Recommend capacity testing no more that every 5 years and more frequent test if the capacity is within 10% of the end of life or design. This is consistent with the nuclear power industry. Table 1b, Station dc supply: – Recommend a change or addition to Table 1b - Recommend a level 2 monitoring (not just a default to the level 1 maintenance activities) which allows for the removal of quarterly "check" of electrolyte levels, DC supply voltage, and DC grounds - if station DC supply (charger) voltage is continuously monitored (eg. one should not have detrimental gassing of a battery if the float voltage of the battery is properly set and monitored). Table 1a, Associated communications systems: The requirement to verify functionality every three months is excessive; verifying this every twelve months is adequate. Tables 1a & 1b – Although the latest standard provided some additional clarification, more clarification is required on what maintenance / testing is ONLY required for UFLS/UVLS protection systems vs. BES protection systems (eg. UFLS / UVLS systems – Is a verification of proper voltage of the DC supply the only battery or DC supply test required (e.g. no state of charge, float voltage, terminal resistance, electrolyte level, grounds, impedance or performance test, etc.) – The requirement to retain data for the two most recent maintenance cycles is excessive. The required data should be limited to the complete data for the most recent cycle, and only the test date for the previous cycle. 2. We Energies does not agree to the implementation plan proposed. While it makes common sense to proceed with R1 prior to proceeding with implementing R2, R3, and R4, the timeline to be compliant for R1 is too short. It will take a considerable amount of resources to migrate the maintenance plan from today's standard to the new standard in phase one. ATC recommends that time to develop and update the revised program be increased to at least one year followed by a transition time for the entity to collect all the necessary field data for the protection system within its first full cycle of testing. (In ATC's case would be 6 years) To address phase two, We Energies believes human and technological resources will be

	overburdened to implement this revised standard as written. The transition to implementing the new program will take another full testing cycle once the program has been updated. Increased documentation and obtaining additional resources to accomplish this will be challenging. Implementation of PRC-005-2 will impact We Energies in the following manner: a. Increase costs: double existing maintenance costs. b. Since there will be a doubling of human interaction (or more), it is expected that failures due to human error will increase, possibly proportionately. c. Breaker maintenance may need to be aligned with protection scheme testing, which will always contain elements that are include in the non-monitored table for 6 yr testing. d. We Energies is developing standards for redundant bus and transformer protection schemes. This would allow We Energies to test the protection packages without taking the equipment out of service. Further if one system fails, there is full redundancy available. With the current version of PRC-005-2, We Energies would need to take an outage to test the protection schemes for a transformer or a bus; there is not an incentive to install redundant schemes. We Energies is working with a condition based breaker maintenance program. This program's value would be greatly diminished under PRC-005-2 as currently written. 3. Consideration also needs to be given for other NERC standards expected to be passed and in the implementation stage at the same time, such as the CIP standards.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The Implementation Plan for Requirement R1 has been changed from three months to twelve months. 3. This issue should be presented to the NERC Standards Committee.
Segment:	3, 5
Organization:	Wisconsin Electric Power Marketing, Wisconsin Electric Power Co.
Member:	James R. Keller, Linda Horn
Comment:	1. Table 1a, Protective Relays: Change 1st line to: "Test and calibrate if necessary the relays…" Table 1a & 1b, Protective Relays:

	3rd line: Change "check the relay inputs…" to "verify the relay inputs…" The term "check" is not defined, whereas "verify" is. Tables 1a & 1b We agree that six / twelve years is an acceptable interval for relay maintenance. Table 1a & 1b, Control & Trip Circuits: The proposed addition to require tripping circuit breakers during Protection System maintenance will require outages and is therefore detrimental to BES reliability and should be removed. Generating unit protection system maintenance is done during scheduled outages. The high voltage breaker on a generating unit often remains energized to back feed and supply station auxiliaries when the generator is offline. The proposed requirement will increase the amount of equipment requiring an outage for maintenance, and possibly the length of the outage, resulting in significantly more equipment out of service as well as increased costs. This requirement also results in greater maintenance efforts and costs when there are redundant protection system equipment (breaker trip coils, lockout relays, etc), which is contrary to good practice and reliability. Many of the breakers that We Energies, as the Distribution Provider, trips from its BES protection systems are not owned by We Energies and are owned by a separate transmission company. The trip testing and maintenance of the transmission company may not coincide with our relay maintenance testing program. The standard shall have allowances for the entity to ONLY test or maintain equipment that it OWNS! Table 1a, Station dc supply: – The activity to verify the state of charge of battery cells is too vague, and requires more specific action. We assume that the drafting committee is recommending specific gravity measurements. Specific gravity measurements have not been shown to be an accurate indicator of state of charge. In addition, as shown in the nuclear power industry, there is no established corrective action that is taken based on specific gravity results (eg. Don't require a test where there is no acceptable corrective action). – The activities to "verify battery continuity" and "check station dc supply voltage" are also vague and need to be more clearly specified what is intended. – The 3 month time interval for battery impedance testing is too frequent. 18 month or annual testing is more appropriate.

	– The 3 calendar year performance or service test is too frequent and will actually remove life from a battery and reduce reliability. Recommend capacity testing no more that every 5 years and more frequent test if the capacity is within 10% of the end of life or design. This is consistent with the nuclear power industry. Table 1b, Station dc supply: – Recommend a change or addition to Table 1b - Recommend a level 2 monitoring (not just a default to the level 1 maintenance activities) which allows for the removal of quarterly "check" of electrolyte levels, DC supply voltage, and DC grounds - if station DC supply (charger) voltage is continuously monitored (eg. one should not have detrimental gassing of a battery if the float voltage of the battery is properly set and monitored). Table 1a, Associated communications systems: The requirement to verify functionality every three months is excessive; verifying this every twelve months is adequate. Tables 1a & 1b – Although the latest standard provided some additional clarification, more clarification is required on what maintenance / testing is ONLY required for UFLS/UVLS protection systems vs. BES protection systems (e.g. UFLS / UVLS systems – Is a verification of proper voltage of the DC supply the only battery or DC supply test required (e.g. no state of charge, float voltage, terminal resistance, electrolyte level, grounds, impedance or performance test, etc.) 2. The requirement to retain data for the two most recent maintenance cycles is excessive. The required data should be limited to the complete data for the most recent cycle, and only the test date for the previous cycle.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data

	retention in the posted Standard to establish this level of documentation.
Segment:	1, 6
Organization:	Great River Energy
Member:	Gordon Pietsch, Donna Stephenson
Comment:	1. In Table 1a section-Station DC Supply – 18 calendar months, under Maintenance Activities column, suggest changing under Verify: Battery terminal connection resistance To: Entire battery bank terminal connection resistance (This could have been interpreted as individual batteries) And change: Battery cell-to-cell connection resistance To: Battery cell-to-cell connection resistance, where an external mechanical connection is available. 2. In Table 1a-Station dc supply (that has a component Valve Regulated Lead-Acid batteries) suggest changing Max Maintenance Interval=3 Calendar Years or 3 Calendar Months to 4 Calendar Years or 12 Calendar Months. Our concern is that the insurance companies may push NERC maintenance intervals on all battery banks not associated with the BES. 3. Table 1a-Station dc supply (that has as a component Lead-Acid batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 4. Table 1a-Station dc supply (that has as a component Nickel-Cadmium batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 5. Table 1b -Level 2 Monitoring Attributes for Component in the row labeled (Control and trip circuitry) we suggest the following change: If a trip circuit comprises multiple paths, at least one of those paths is monitored. Alarming for loss of continuity or dc supply for trip circuits is reported to a location where action can be taken. 6. While all tripping circuits are not completely monitored, the trip coils and the outdoor cable runs are completely monitored. The only portion that would not be monitored is a portion of inter and intra-panel wiring having no moving parts located in a control house. Our company has extremely low failure rate of panel wiring and terminal lugging. I don’t think that there is provision for moving control and trip circuitry to performance based maintenance? This control circuitry should be maintained less frequent than un-monitored trip circuits (6 years).

Response:	Thank you for your comment. 1.The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. 2. NERC Standards are limited to facilities and equipment related to the BES. How the Standard may be otherwise used is outside the scope of NERC Standards. 3. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Vented Lead Acid and Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 4. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-56. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. Nothing in the draft Standard (including Attachment A) precludes an entity from using performance-based maintenance for dc control circuits.
Segment:	3
Organization:	Great River Energy
Member:	Sam Kokkinen
Comment:	1. In Table 1a section-Station DC Supply – 18 calendar months, under Maintenance Activities column, suggest changing under Verify: Battery terminal connection resistance To: Entire battery bank terminal connection resistance (This could have been interpreted as individual batteries) And change: Battery cell-to-cell connection resistance To: Battery cell-to-cell connection resistance, where an external mechanical connection is available. 2. In Table 1a-Station dc supply (that has a component Valve Regulated Lead-Acid batteries) suggest changing Max Maintenance Interval=3 Calendar Years or 3 Calendar Months to 4 Calendar Years or 12 Calendar Months. Our concern is that the insurance companies may push NERC maintenance intervals on all

	battery banks not associated with the BES. 3. Table 1a-Station dc supply (that has as a component Lead-Acid batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 4. Table 1a-Station dc supply (that has as a component Nickel-Cadmium batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 5. Table 1b -Level 2 Monitoring Attributes for Component in the row labeled (Control and trip circuitry) we suggest the following change: If a trip circuit comprises multiple paths, at least one of those paths is monitored. Alarming for loss of continuity or dc supply for trip circuits is reported to a location where action can be taken.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. 2. NERC Standards are limited to facilities and equipment related to the BES. How the Standard may be otherwise used is outside the scope of NERC Standards. 3. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Vented Lead Acid and Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 4. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
Segment:	5
Organization:	Great River Energy

Member:	Cynthia E Sulzer
Comment:	1. In Table 1a section-Station DC Supply – 18 calendar months, under Maintenance Activities column, suggest changing under Verify: Battery terminal connection resistance To: Entire battery bank terminal connection resistance (This could have been interpreted as individual batteries) And change: Battery cell-to-cell connection resistance To: Battery cell-to-cell connection resistance, where an external mechanical connection is available. 2. In Table 1a-Station dc supply (that has a component Valve Regulated Lead-Acid batteries) suggest changing Max Maintenance Interval=3 Calendar Years or 3 Calendar Months to 4 Calendar Years or 12 Calendar Months. Our concern is that the insurance companies may push NERC maintenance intervals on all battery banks not associated with the BES. 3. Table 1a-Station dc supply (that has as a component Lead-Acid batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 4. Table 1a-Station dc supply (that has as a component Nickel-Cadmium batteries) Max Maintenance Interval=6 Calendar Years suggest changing to 10 Calendar Years. Reason: performance tests may degrade the battery. 5. Table 1b -Level 2 Monitoring Attributes for Component in the row labeled (Control and trip circuitry) we suggest the following change: If a trip circuit comprises multiple paths, at least one of those paths is monitored. Alarming for loss of continuity or dc supply for trip circuits is reported to a location where action can be taken. 6. While all tripping circuits are not completely monitored, the trip coils and the outdoor cable runs are completely monitored. The only portion that would not be monitored is a portion of inter and intra-panel wiring having no moving parts located in a control house. Our company has extremely low failure rate of panel wiring and terminal lugging. I don’t think that there is provision for moving control and trip circuitry to performance based maintenance? This control circuitry should be maintained less frequent than un-monitored trip circuits (6 years).
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-

	4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. 2. NERC Standards are limited to facilities and equipment related to the BES. How the Standard may be otherwise used is outside the scope of NERC Standards. 3. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Vented Lead Acid and Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 4. The SDT disagrees, and believes that a performance test at 6-year intervals is appropiate for Ni-Cad batteries. A properly maintained battery, according to various credible references (from IEEE, EEI, EPRI, various manufacturers, etc.), can easily handle multiple deep discharges over its expected life. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. Nothing in the draft Standard (including Attachment A) precludes an entity from using performance-based maintenance for dc control circuits.
Segment:	1, 3, 5, 6
Organization:	Dominion Virginia Power, Dominion Resources Services, Dominion Resources, Dominion Resources Inc.
Member:	John K Loftis, Michael F Gildea, Mike Garton, Louis S Slade
Comment:	1. There is not enough clarity to clearly identify which protection system components are necessary to protect the BES. We suggest that 4.2.1 be revised to read “protection systems that are designed to provide protection for the BES.” 2. The Standard does not provide a grace period if an entity is unable to meet the maintenance requirement for extenuating circumstances. For example if an entity has to divert maintenance resources to storm restoration. We do not believe the reliability of the Bulk Electric System will be compromised if an entities' maintenance program slips by a few months due to extreme events, especially if it is brought back on track within a short time frame. 3. We are opposed to the six calendar year maximum maintenance interval for microprocessor relays that have auxiliaries.

Response:	Thank you for your comment. 1. The SDT disagrees and believes that the Applicability is correct as stated. 2. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1.
Segment:	3
Organization:	Allegheny Power
Member:	Bob Reeping
Comment:	The draft standard expects 100% compliance for millions of protection system components at all times. The standard should consider a statistically based performance metric instead of a performance target that expects 100% compliance.
Response:	Thank you for your comment. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	1
Organization:	Public Service Company of New Mexico
Member:	Laurie Williams
Comment:	Overall, the inclusion of several types of protective relay systems into one standard is reasonable and should include those associated with UVLS and UFLS. Even so, the standard is unmanageably cumbersome with far too many details. Although it has been said that protection systems include the instrument transformers, DC system and sometimes the breaker trip coils it is equally as true to say that the protective relay systems depend on those to effectively respond to the anomaly, typically a short circuit fault. With that said it is those item’s maintenance that should potentially be moved to different standards to improve clarity. Their inclusion into this standard by size and complexity overwhelms this standard. This standard should include only those items that utilize similar equipment and techniques to maintain. In this case and at this time that means computer-controlled test sets that also generate the records necessary to prove compliance. Even after distilling the standard to only protective relay systems the complexities and details used to explain

	the non-time-based methodologies contribute to the confusion. But the availability of those methodologies is important and probably cannot be in a different standard. It therefore seems imperative with the inclusion of those methodologies that the DC support system maintenance and instrument transformer maintenance have different standards. The inclusion of so much explanation inside the standard is distracting and perhaps contributes to the confusion. PNM also offers the following specific feedback on the proposed standard: 1. -R1.1: Uniquely identifying ‘Protection System components’ as asked for in R1.1 may be problematic given protective systems may be logged in maintenance databases as packages rather than individual elements. Because the elements within each package are tested as a group, the requirement to individually list the components of the package and track them as such would provide no additional benefit to system reliability. 2. -The activities outlined in Tables which begin on Page 9 of the proposed Standard are difficult to align with the VSLs given in the standard. 3. -The Tables suggest that test trips of equipment are required as part of the scheduled program, but test trips of equipment may pose a hazard to the BES if the equipment fails due to multiple test trips or mis-operates to remove additional BES facilities from service (ex., breaker failure mis-operation during line relay trip testing), which may pose a potential risk to the BES. An example would be 8 test trips of a generator breaker in order to make it through the testing of all of the system components that have the ability to trip the generator lockout and therefore the breaker. Suggest wording to be added that would include some sort of breaker tripping simulation (test box, lockout simulator, etc.) that could be built into the circuit? 4. -It is still unclear how the audit of an entity’s compliance which occurs during the transition time will be viewed if it chooses to immediately transition all of its components to the intervals defined in the standard, but were out of the interval defined by the entity under PRC-005-1? 5. -From the Table 1a – “Verify proper function of the current and voltage signals” is not defined. Is the verification visual? How is this easily measured on circuits with EM relays still in service? 6. -If exposure to BES is evident during a testing interval, how does the TO or GO coordinate with its

	Reliability Coordinator to delay or push out testing that may compromise the testing due date? Example – critical transmission circuit is removed from service under forced outage, testing due on adjacent or other critical circuit where test tripping could compromise BES. What is the documentation procedure to get an exception or coordinate with RC to mitigate? This has been a big hole in any testing program; there is no way to file an exception due to unforeseen circumstances like this one. 7. -Is it recommended that there be on PSMP per Company no matter how many Entities they may have or should there be one PSMP for each entity? Standard is unclear on this issue.
Response:	Thank you for your comment. 1. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. The VSLs have been modified to correspond. 3. The Standard allows functional testing, if used, to be done in overlapping segments to avoid specifically the situations you cite. 4. This is a concern that should be submitted to the compliance monitor. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. Also please see Section 15.2 of the Supplementary Reference and FAQ II.3.A, II.3.B, II.3.C, and II.3.D. 6. It would seem prudent to schedule your maintenance to allow for such contingencies. "Grace periods" within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard. 7. This is up to the entity. For example, you may choose to have one PSMP for a transmission function and a separate one for a generation function.
Segment:	1
Organization:	PPL Electric Utilities Corp.
Member:	Brenda L Truhe
Comment:	PPL EU is voting negative because the definition of Protective Relays is not limited to only those devices that use electrical quantities as inputs (exclude pressure, temperature, gas, etc).
Response:	Thank you for your comment. The Standard does not preclude entities from maintaining such devices or

	including them in their PSMP.
Segment:	1, 3
Organization:	Platte River Power Authority
Member:	John C. Collins, Terry L Baker
Comment:	The standard is very difficult to interpret even with all of the supplemental documentation and we believe this will lead to more non-compliance of the standard without any increase to system reliability and in some cases the required testing will actually reduce system reliability by putting the system at unnecessary risk to complete the testing.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
Segment:	1
Organization:	Nebraska Public Power District
Member:	Richard L. Koch
Comment:	The negative vote is based upon functional trip checking and the affect that it will have on the BES.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5, which no longer includes any specific requirements for functional testing. Performance-based maintenance can also be applied to these functions.
Segment:	1
Organization:	National Grid
Member:	Saurabh Saksena
Comment:	1. National Grid does not agree with the proposed implementation plan. The time provided for the first phase “at least six months” is too open ended and does not give entities a clear timeline. National Grid suggests 1 year for the first phase. National Grid also suggests phasing out the second phase in stages. 2. National Grid does not support the VSL criteria based on "total number of components". Calculating total number of components will be hugely costly and does not enhance any reliability. It will also take away the much needed resources required for maintenance.
Response:	Thank you for your comment.

	1. This comment appears to be related to the Implementation Plan for the definition (which was independent to the Standard), not to the Standard. 2. The SDT believes that the only alternative to these criteria is to provide a binary VSL, which would mean that any non-compliance would be “Severe”.
Segment:	3
Organization:	Niagara Mohawk (National Grid Company)
Member:	Michael Schiavone
Comment:	National Grid does not agree with the proposed implementation plan. The time provided for the first phase “at least six months” is too open ended and does not give entities a clear timeline. National Grid suggests 1 year for the first phase. National Grid also suggests phasing out the second phase in stages.
Response:	Thank you for your comment. This comment appears to be related to the Implementation Plan for the definition (which was independent to the Standard), not to the Standard.
Segment:	1, 3
Organization:	MidAmerican Energy Co.
Member:	Terry Harbour, Thomas C. Mielnik
Comment:	For control and trip circuit maintenance the requirement includes “a complete functional trip test”. In order to accomplish this type of testing given current design of lock-out relay and interrupting device trip circuitry multiple breakers and line terminal outages would be required simultaneously. In addition this type of testing has the potential to result in unintentional tripping of equipment that could cause equipment damage and customer outages. Segmentation of trip circuits by lifting wires has the potential for incorrect restoration following testing. This type of testing has the potential to degrade system reliability as multiple entities schedule this work. An alternate to complete functional testing that does not potentially degrade system reliability should be substituted.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5, which no longer includes any specific requirements for functional testing. Performance-based maintenance can also be applied to these functions. Electromechanical devices such as aux or lockout relays remains at 6 years, as these devices contain “moving parts” which must be periodically exercised to remain reliable.

Segment:	1
Organization:	Idaho Power Company
Member:	Ronald D. Schellberg
Comment:	Monitoring the state of charge using current measurement methods would increase the workload and staffing requirements beyond what we feel is necessary with little additional value to reliability beyond specific gravity measurements.
Response:	Thank you for your comment. The Standard is requiring that state-of-charge be determined, but does not specify how. Specific gravity testing (no longer required within the Tables) would be one method.
Segment:	1
Organization:	Commonwealth Edison Co.
Member:	Daniel Brotzman
Comment:	1. Nuclear generators are licensed to operate and regulated by the Nuclear Regulatory Commission (NRC). Each licensee operates in accordance with plant specific Technical Specifications (TS) issued by the NRC which are part of the stations' Operating License. TS allow for a 25% grace period that may be applied to TS Surveillance Requirements. Referencing NRC issued NUREGs for Standard Issued Technical Specifications (NUREG-143 through NUREG-1434) Section 3.0, "Surveillance Requirement (SR) Applicability," SR 3.02 states the following: "The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met." The NRC Maintenance Rule (10 CFR 50.65) requires monitoring the effectiveness of maintenance to ensure reliable operation of equipment within the scope of the Rule. Adjustments are made to the PM (preventative maintenance) program based on equipment performance. The Maintenance Rule program should provide an acceptable level of reliability and availability for equipment within its scope. The NRC has provided grace periods for certain maintenance and surveillance activities. Exelon strongly believes that SDT should consider providing this grace period to be in agreement and be consistent with the NRC methodology. Not providing this grace period will directly affect the existing nuclear station practices (i.e., how stations schedule and perform the maintenance activities) and may lead to confusion as implementing dual requirements is not the normal station process. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). If for some reason the schedule

	window shifts by even a few days, an issue of potential non-compliance could occur for scheduled outage-required tasks. The possibility exists that a nuclear generator may be faced with a potential forced maintenance outage in order to maintain compliance with the proposed standard. For the requirements with a maximum allowable interval that vary from months to years (including 18 Months surveillance activities), the SDT should consider an allowance for NRC-licensed generating units to default to existing Operating License Technical Specification Surveillance Requirements if there is a maintenance interval that would force shutting down a unit prematurely or face non-compliance with a PRC-005 required interval. Therefore, at a minimum, maintenance intervals should include an allowance for any equipment specifically controlled within each licensee's plant specific Technical Specifications to implement existing Operating License requirements if such a conflict were to occur. 2. Additionally we are requesting to have the first phase of implementation extended from 6 months to 1 year. This will provide adequate time for development of documentation, training for all personnel, and testing the implementation of the new process (es).
Response:	Thank you for your comments. 1. The SDT understands that nuclear power plants are licensed and regulated by the NRC, has a general understanding of the role that plant Technical Specifications (TS) and associated Surveillance Requirements (SR) play in the facilities' operating licenses, and has tried to be sensitive to potential conflicts between PRC-005-2 and NRC requirements. The SDT believes that the majority of components making up the Protection Systems for in-scope generating facilities as discussed in Section 4.2.5 of the Standard would be considered balance of plant equipment and, therefore, not subject to NRC issued TS and associated SR requirements. While availability of plant auxiliary sources to the plant's safety related equipment is addressed by TS and associated SR requirements, these documents are focused on the effects that the availability of these transformers have on reactor safety rather than specifying maintenance and testing requirements for the Protection Systems for these transformers. The SDT recognizes that some battery systems may serve as a source of DC power to both reactor

	safety systems and to protection systems discussed in Section 4.2.5. The SDT acknowledges that there might be plant TS and SR applicable to these batteries. However, the SDT believes that the 3-month and 18-month inspection requirements called for in PRC-005-2 would be no more onerous than plant TS requirements for routine online safety system battery inspections and, furthermore, would not necessitate a plant outage. The SDT recognizes that the PRC-005-2 requirement for validating battery design capability via battery capacity testing would require a plant outage. However, it is the opinion of the SDT that the maximum allowed battery capacity testing intervals of not to exceed 6 calendar years for vented lead acid or NiCad batteries (not to exceed 3 calendar years for VRLA batteries) could easily be integrated within the plant's routine 18 month to 2 year interval refueling outage schedule. The SDT believes that PRC-005-2 is complimentary to the NRC Maintenance Rule in that PRC-005-2 requirements allow for the leveraging of the entire electrical power industry experience in establishing minimum maintenance activities and maximum allowed maintenance intervals necessary to ensure reliable protection system performance. Please see Supplemental Reference Section 8.4 for further discussion for the SDT's rationale for exclusion of grace periods. Please see FAQ IV.2.C for further discussion of impact of PRC-005-2 testing requirements on power plant outage schedules. The challenge of integrating PRC-005-2 testing requirements with a plant's outage schedule is not unique to nuclear plants. Finally, the SDT notes that an entity may build grace periods into its own PSMP as long as the maximum allowed time intervals of PRC-005-2 are not exceeded. If an entity wishes to build a 25% grace period into its program, it may do so by setting its program maintenance and testing intervals at <80% of the PRC-005-2 maximum allowable time interval. 2. The Implementation Plan for R1 has been modified to 12 months.
Segment:	1, 3, 6
Organization:	Cleco Power LLC, Cleco Utility Group, Cleco Power LLC
Member:	Danny McDaniel, Bryan Y Harper, Matthew D Cripps

Comment:	1. The revised definition to Protection System should include the following exception. "Devices that sense non electrical conditions, such as thermal or transformer sudden pressure relays are not included." The Drafting Team has included this note in the standard, but not in the definition. For consistence across the standards, see PRC-004, which references System Protection, the same definition should be used. 2. See Table 1a, Station dc supply. One of the checks is to verify battery cell-to-cell connection resistance. This is not possible in all battery sets. 3. As written, the standard requires testing of batteries, DC control circuits, etc., of distribution level protection components associated with UFLS and UVLS. This is beyond the scope of the Reliability Standards which should focus on the BES. Only include the UFLS or UVLS relays in the program. 4. Revise M1 to reference Protection System definition.
Response:	Thank you for your comment. 1. The definition of "Protection System" has been modified essentially as you suggest. 2. "Cell" has been replaced with "cell/unit." 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4 and 1-5.
Segment:	1
Organization:	BC Transmission Corporation
Member:	Gordon Rawlings
Comment:	1. - Purpose unclear "affecting the reliability of the BES" is open to interpretation should read "applied on or designed to provide protection of the BES" 2. - Monitoring levels (1, 2 and 3) are not clear 3. - Maintenance activities are not well defined 4. - Some utilities base their maintenance program on a fiscal year where all scheduled maintenance for the fiscal year must be completed by the end of the fiscal year. It would take considerable effort to switch to end of calendar year with zero improvement in overall reliability.

	5. - For maintenance scheduled in terms of a number of months, requiring that maintenance be completed by the end of scheduled month does not leave much margin if maintenance is delayed for a legitimate reason.
Response:	Thank you for your comment. 1. The purpose can be general; Requirement R1 is worded as you suggest. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. Various sections of the FAQ have provided suggestions about how to conduct the activities in the tables. 4. With the vast array of entities subject to compliance monitoring, it would be very difficult for the ERO to assess compliance for varying "years." Additionally, the SDT understands that most compliance monitors currently request data on a calendar year basis when assessing compliance. 5. The entity is encouraged to schedule the maintenance activities to allow for contingencies.
Segment:	1
Organization:	Associated Electric Cooperative, Inc.
Member:	John Bussman
Comment:	There needs to be grace periods for the battery testing of 3 months. Testing a complete transmission system over 3 states in every 3 months and not be one day past due will b a challenge.
Response:	Thank you for your comment. The 3-month maintenance for station dc supply is comprised of inspections that don't require testing.
Segment:	1, 3, 5
Organization:	Arizona Public Service Co., APS
Member:	Robert D Smith, Thomas R. Glock, Mel Jensen
Comment:	1. The generator Facilities subsections 4.2.5.1 through 5 are too prescriptive and inconsistent with sections 4.2.1 through 4. Recommend this section be limited to description of the function as in the preceding sections. 2. In addition, the associated maintenance activities in Table 1 are too prescriptive.

	3. The activities needed to ensure the reliable service of the relay or device should be left up to the discretion of the utility. One example, due to the change to the Protection System definition and establishing a new PSMP with prescriptive maintenance activities relative to the voltage and current sensing devices has created a situation where data from original or prior verification is not available or not at the interval to meet the data retention requirement. Although, methods of determining the integrity of the voltage and current inputs into the relays were used to ensure reliability of the devices met the utilities performance requirements, they may not meet the interval requirement and would then be considered a violation due to changes in the standard. 4. For data requirements, an initial exemption is recommended for the two recent most recent performances of maintenance activities in the first maintenance interval for this component due to the long maintenance interval, the changes in the standard definitions and the prescriptive maintenance activities. 5. Clarification is needed on “Note 1” in Table 1a, which appears to be used to define a calibration failure. How would it be used in Time Based Maintenance? In PRC-005-2 Attachment A: Criteria for a Performance-Based Protection System Maintenance Program, a calibration failure would be considered an event to be used in determining the effectiveness of Performance Based Maintenance. It is unclear in how it will be used in time based maintenance.
Response:	Thank you for your comment. 1. The SDT believes that transmission lines, UFLS, UVLS, and SPS are clear without additional granularity, but that the additional granularity regarding generation plants is necessary. This is illustrated by numerous questions regarding “what is included for generation facilities” relative to PRC-005-1. 2. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities. 3. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities. It seems reasonable that you cannot be held accountable for a requirement before it becomes effective. 4. In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation. The Tables have been rearranged and considerably revised to improve clarity, and the cited note removed. Please see new

	Tables 1-5.
Segment:	1
Organization:	American Transmission Company, LLC
Member:	Jason Shaver
Comment:	ATC does not support the existing 2nd Draft of PRC-005-2 Standard because it is our opinion that: • There is a high probability that system reliability will be reduced with this revised standard. • The number of unplanned outages due to human error will increase considerably. • Availability of the BES will be reduced due to an increased need to schedule planned outages for test purposes (to avoid unplanned outages due to human error). • To implement this standard, an entity will need to hire additional skilled resources that are not readily available. (May require adjustments to the implementation timeline.) • The cost of implementing the revised standard will approximately double our existing cost to perform this work. ATC requests that relevant reliability performance data (based on actual data and/or lessons learned from past operating incidents, Criteria for Approving Reliability Standards per FERC Order 672) be provided to justify the additional cost and reliability risks associated with functional testing.
Response:	Thank you for your comment. The SDT believes that performing these maintenance activities will benefit the reliability of the BES.
Segment:	1, 5, 6
Organization:	American Electric Power, AEP Service Corp, AEP Marketing
Member:	Paul B. Johnson, Brock Ondayko, Edward P. Cox
Comment:	AEP supports the progress of this draft standard, largely supports much of the elements within. However, we provide the following summary of the comments provided in response to the most recent (2nd) draft, which we suggest the SDT consider. 1. In Table 1a for the component “Station dc Supply (used only for UVLS and UFLS)”, the interval

	prescribed is "(when the associated UVLS or UFLS system is maintained)" and the activity is to "verify the proper voltage of the dc supply". The description of the interval "(when the associated UVLS or UFLS system is maintained)" needs to be changed. Relay personnel do not generally take battery readings. The interval should read “according to the maximum maintenance interval in table 1a for the various types of UFLS or UVLS relays". The testing does not need to be in conjunction with the relay testing, it is only the test interval that is important, although relay operation during relay testing is a good indicator of sufficient voltage of the battery. 2. The monitoring and/or maintenance activities listed for batteries are not appropriate in Tables 1b and 1c. There are no commercial battery monitors that monitor and alarm for electrolyte level of all cells. Why not move the electrolyte level to the 18 month inspection and actually open the possibility of condition monitoring to commercially available devices? Or give an option to do the electrolyte check at other time intervals (perhaps 12 months) by visual electrolyte inspection and still allow the monitoring of other functions on the listed 6 year schedule using condition monitoring. It makes no sense to prescribe an unattainable condition monitoring solution. The way that the tables are written, there is no advantage to use the charger alarms since battery maintenance requirements are not reduced in any way. 3. In regards to "Measures and Data Retention", the measure includes the entire definition of "Protection System". Remove the definition from the measure and let the definition stand alone in the NERC glossary. 4. In regards to Data Retention, this calls for past 2 distinct maintenance records to be kept. Since UFLS interval can be 12 years, this would mean that we would need to keep records for 24 years. This is not realistic and consideration should be given to choosing a reasonable retention threshold. 5. The "Supplementary Reference" and the "Frequently-Asked Questions" document should be combined into a single document. This document needs to be issued as a controlled NERC approved document. AEP suggests that the document be appended to the standard so it is clear that following directions provided by NERC via the document are acceptable, and to avoid an entity being penalized during an audit if the auditor disagrees with the document’s contents. 6. NiCAD batteries should not be treated differently from Lead-Acid batteries. NiCAD battery condition can be detected by trending cell voltage values. Ohmic testing will also trend battery conditions and locate failed cells (although will usually lag behind cell voltages). A required load test is detrimental to the NiCAD

	manufacturer's business, and will definitely hurt the NiCAD business for T&D applications. Historically NiCADs may have been put into service because of greater reliability, smaller space constraints, and wider temperature operation range. "Individual cell state of charge" is a bad term because it implies specific gravity testing. Specific gravity cannot be measured automatically (without voiding battery warranty or using an experimental system), and when it is measured, it is unreliable due to stratification of the electrolyte and differing depths of electrolyte taken for samples. "Battery state of charge" can be verified by measuring float current. Once the charging cycle is over the battery current drops dramatically, and the battery is on float, signaling that the battery has returned to full state of charge. This is an appropriate measure for Level 3 monitoring as float current monitoring is a commercially viable option and electrolyte level monitoring is not. 7. In Table 2b, why is Ohmic testing required if the battery terminal resistance is monitored? Cell to cell and battery terminal resistance should not be monitored because they will be taken in 18 month intervals. This further supports the argument that the battery charger alarms would be sufficient for level 2 monitoring, while keeping an 18 month requirement for Ohmic testing, electrolyte level verification, and battery continuity (state of charge). Automatic monitoring of the float current should be sufficient for level 3 monitoring as it gives state of charge of the string, and battery continuity (detect open cells). Shorted cells will still be found during the Ohmic testing and a greater interval is sufficient to locate these problems.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 3. The SDT modified the Measure as you suggested. 4. In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one, as well as data to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted Standard to establish this level of documentation. The SDT disagrees that the documents should be combined. The Supplementary Reference is a holistic presentation of rationale and basis for the various elements of the Standard – discussing mostly the "what" behind the requirements. The FAQ, on the other hand, presents responses to specific frequently asked questions, and, as such, offers more-focused advice on specific subjects, and is more of an example/how-to discussion. The FAQ is primarily a means of capturing some of the most prevalent comments offered

	on the Standard by various entities, with the SDT's response. The SDT believes that the format of the FAQ is a more effective means of presenting the included information than it would be to include this information within the text of the Supplementary Reference document. 5. The SDT believes that since the IEEE Stationary Battery Committee has determined that VRLA batteries and Ni-Cad batteries are different enough to require separate IEEE Standards (IEEE 1188 and IEEE 1106, respectively), these battery technologies are different enough to be treated separately within PRC-005-2. The SDT has drawn upon these IEEE Standards, as well as other sources (EPRI, etc) to develop the requirements of PRC-005-2. The trending activity cited has not been shown to be effective for Ni-Cad batteries (see FAQ II.5.G), and thus a performance test must be performed; the performance test may take many forms. The Tables have been rearranged and considerably revised to improve clarity, and all references to specific gravity have been removed. Please see new Table 1-4. Determining the "state of charge" by monitoring the float voltage may be relevant to the overall station battery, but does not provide an indication of the condition of individual cells as required within the new Table 1-4. 6. Battery terminal resistance shows the condition of the external connections, but reveals nothing regarding the internal condition of the individual cells. Measuring the internal cell/unit resistance provides an opportunity to trend the cell condition over time by verifying the electrical path through the electrolyte within the battery. The ohmic testing is not intended to look for open cells/units, but instead at the ability of the individual cell/unit to perform properly. The new Table 1-4 clarifies that, if the electrolyte level is monitored, the internal ohmic testing need only be performed every six years. Please see FAQ II.5.B, II.5,C and II.5.D for a discussion about continuity.
Segment:	1
Organization:	Ameren Services
Member:	Kirit S. Shah
Comment:	We commend the SDT for developing a generally clear and well documented second draft. The SDT considered and adopted many industry comments on the first draft. It generally provides a well reasoned and balanced view of Protection System Maintenance, and good justification for its maximum intervals. Ameren generally agrees that this second draft will be beneficial to BES reliability, but several inconsistencies, unclear items, and a couple issues need to be addressed before we will be able to support it. (a)The tables still contain several inconsistencies and items needing clarification

	(b)Implementation of the PSMP must align with the start of a calendar year (c) The expectation of perfection in maintaining the extremely high volume of Protection System parts is inconsistent with accepted engineering practice (a fundamental tenet is that tolerances must be allowed for) (d)The Project 2009-17 interpretation that clarifies the transmission Protection System border must be incorporated. (e)Generating Plant system-connected Station Service transformers should not be included as a Facility because they are serving load.
Response:	Thank you for your comment. a. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. b. The SDT Guidelines, which were endorsed by the NERC Standards Committee in April 2009, establishes that proposed effective dates "must be the first day of the first calendar quarter after entities are expected to be compliant." The Implementation Plan is in accordance with these guidelines. c. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. d. When the interpretation (Project 2009-17) is approved, the SDT for PRC-005-2 will consider if the interpretation is appropriate for PRC-005-2 and make associated changes. e. The "load" being served by the Station Service Transformer may be essential to operation of the generating plant, and therefore is not the same as general distribution system load. Therefore, the SDT believes that these system components must remain within the Applicability section of the Standard.
Segment:	3
Organization:	Florida Power Corporation
Member:	Lee Schuster
Comment:	Progress Energy does not believe that the definition should be implemented separately from and prior to the implementation of PRC-005-2. We believe there should be a direct linkage between the definition's effective date to the approval and implementation schedule of PRC-005-2. Since this new definition should be directly

	linked to the proposed revised standard, it would be premature to make this new definition effective prior to the effective date of the new standard. We believe that changes to the maintenance program should be driven by the revision of the PRC standard, not by the revision of a definition.
Response:	Thank you for your comment. When the Board of Trustees was asked to approve an interpretation of PRC-005-1 that was written by the PSMT SDT, the board acknowledged the reliability gap identified by the drafting team caused by the definition of "Protection System" and directed that work to close this reliability gap should be given priority. To close this reliability gap the revised definition must be applied to PRC-005-1 as soon as practical - not years from now. The Implementation Plan now proposes at least 12 months for entities to apply the new definition to PRC-005-1, and that should give entities time to apply the new definition to PRC-005-1.
Segment:	1, 3, 5, 6
Organization:	Bonneville Power Administration
Member:	Donald S. Watkins, Rebecca Berdahl, Francis J. Halpin, Brenda S. Anderson
Comment:	Please see BPA's comments submitted during the concurrent formal NERC comment period ending July 16, 2010.
Response:	Thank you for your comment. Please see our responses on the Consideration of Comments from the cited comment period.
Segment:	6
Organization:	Northern Indiana Public Service Co.
Member:	Joseph O'Brien
Comment:	1. It appears that some batteries are not able to accommodate all of the tests required in this standard. 2. The standard also unreasonably requires 100% compliance for millions of protection system components.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 2. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.

Segment:	6
Organization:	Lakeland Electric
Member:	Paul Shipps
Comment:	As written, is opens the standard to Technical Feasibility Exceptions due to some batteries not being able to accommodate all of the tests proscribed in the draft standard
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. "Cell" has been replaced with "cell/unit" to address this concern. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system.
Segment:	4
Organization:	Fort Pierce Utilities Authority
Member:	Thomas W. Richards
Comment:	1. The battery test procedure that calls for intra-cell resistance cannot be performed on batteries that have internal cell-to-cell straps. A brief rewording of the requirement would take care of this. We recommend the minimum requirement be changed to measure the internal resistance at the battery terminal. The reading of individual cells is of little use anyway since a bad reading will result in having to replace the entire jar. 2. The draft standard would cause NERC to regulate through the standards battery testing, DC circuit testing, etc. on distribution elements with no significant improvement to BES reliability, which is beyond the statutory scope of the standards. 3. The standard unreasonably retains the "100% compliance" paradigm for thousands, if not millions of protection system components. The audit becomes an investigation at this point and is not feasible even for mid-sized entities that have hundreds of components subject to this standard.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. "Cell" has been replaced with "cell/unit" to address this concern. 2. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system.

	3. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	5
Organization:	PowerSouth Energy Cooperative
Member:	Tim Hattaway
Comment:	The maintenance and testing requirements are too prescriptive and leave little room for an entity to make decisions regarding what type maintenance and testing they deem appropriate. Some of the maintenance and testing methods and intervals as defined in the standard, e.g. the standard calls for a maximum 3 month testing interval for sealed station batteries if performing impedance testing, do not seem to improve reliability at all. The migration from compliance with the present standard to version 2 as prescribed would be a monumental administrative task
Response:	Thank you for your comment. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	5
Organization:	Liberty Electric Power LLC
Member:	Daniel Duff
Comment:	Required tasks are overly prescriptive.
Response:	Thank you for your comment. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	5
Organization:	ExxonMobil Research and Engineering
Member:	Martin Kaufman
Comment:	In the past, NERC has taken care to avoid instructing an entity on how to create its compliance program. The draft standard PRC-005-2 departs from this tradition and partially defines a maintenance and testing program that all entities will be required to follow until such a time that the entity has collected enough data to

	implement the performance based method defined in Attachment A. Additionally, some of the maintenance and testing intervals defined in the tables (e.g. station battery testing) mimic industry recommended test intervals instead of defining maximum acceptable testing intervals.
Response:	Thank you for your comment. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	4
Organization:	Y-W Electric Association, Inc.
Member:	James A Ziebarth
Comment:	From Question 1 on the comment form: Many of the changes to the proposed standard are reasonable and improve the clarity of the standard and its requirements. However, Y-WEA concurs with others on their comments regarding the testing of battery cell-to-cell connection resistance. Many types of stationary batteries are actually blocks of two or more cells that are internally connected. This requirement would necessitate either some sort of feasibility exception process (which, as shown by the TFE process with the CIP standards can be very difficult, cumbersome, and time-consuming to develop and administer) or replacement of the batteries in question, which would pose enormous burdens on small entities that must comply with this standard. The language in this requirement should be changed from "cell-to-cell" to "unit-to-unit" in order to avoid these issues. From Question 7 on the comment form: 1. Y-WEA concurs with others regarding the timing of required battery tests. The IEEE standards referenced indicate target maintenance intervals. In order to remain reasonable, then, this compliance standard needs to allow some buffer between a targeted maintenance and inspection interval and a maximum enforceable maintenance and inspection interval. The suggestion of a four-month maximum window is reasonable and should be incorporated into the standard. 2. Y-WEA is also concerned with R1.1's language indicating that all components must be identified with no defined "floor" for the significance of a component to the Protection System. The SDT cannot possibly expect that a parts list containing every terminal block, wire and jumper, screw, and lug is going to be maintained with every single part having all the compliance data assigned to it, but without clearly stating this, that is exactly the degree of record-keeping that some overzealous auditor could attempt to hold the registered entity to. The FAQ is much clearer as to what is and is not a component and should be considered

	for the standard. 3. Y-WEA also concurs with others' comments regarding the testing of batteries and DC control circuits associated with UFLS relaying. Many UFLS relays are installed on distribution equipment. Furthermore, many distribution equipment vendors are including UFLS functions in their distribution equipment. For example, many recloser controls incorporate a UFLS function in them. These controls and the reclosers they are attached to, however, are strictly distribution equipment. 16 USC 824o (a)(1) limits the definition of the Bulk-Power System to “not include facilities used in the local distribution of electric energy.” A distribution recloser and its control clearly fall into this exclusion. 16 USC 824o (i) (1) prohibits the ERO from developing standards that cover more than the Bulk-Power System. As such, the DC control circuitry and batteries associated with many UFLS relaying installations are precluded from regulation under NERC’s reliability standards and may not be included in this standard because they are distribution equipment and therefore not part of the Bulk-Power System. The proposed standard needs to be rewritten to allow for this exclusion and to allow for the testing of only the UFLS function of any distribution class controls or relays.
Response:	Thank you for your comment. From Question 1 - The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. From Question 7 – 1. The SDT disagrees. You should complete the activities within the intervals specified. 2. Requirement R1, part 1.1, has been revised to state, “Address all Protection System component types” in consideration of your comment. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4 and 1-5.
Segment:	4
Organization:	Old Dominion Electric Coop.
Member:	Mark Ringhausen
Comment:	While the SDT has made progress, there are still some areas that need additional work:

	1. Battery testing of the cell to cell should be unit to unit or some other words for battery system locations that do not allow cell to cell testing. 2. Battery checks on a three months period seems to aggressive and should be moved to six months. 3. Clarify your intent to test the CTs and PTs as some commenters have read it that one does not have to test these pieces of equipment per this standard. 4. Require UFLS and UVLS testing to trip the breaker/recloser when this can be done without tripping of load (by-pass is available).
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. 2. The SDT disagrees. You should complete the activities within the intervals specified. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
Segment:	3
Organization:	Springfield Utility Board
Member:	Jeff Nelson
Comment:	Please see SUB's comments on the comment form
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	3
Organization:	Salem Electric
Member:	Anthony Schacher
Comment:	The standard is getting better but leaves to many holes for utilities that do not have specific equipment and would need to file a TFE to exempt their facilities.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.

Segment:	3
Organization:	Public Utility District No. 2 of Grant County
Member:	Greg Lange
Comment:	Although this version is a significant improvement in several areas from the past version there are still several things that need clarification or overhaul. 1. We find an inconsistency between the component based approach to version 2 and the way protective systems are maintained. The description of components still needs work as well. 2. It appears that in the new version battery chargers and cables could be professionally judged to be a part of the circuitry. We don't believe this is the intent, but again leaves too much to the imagination of an overzealous auditor. Truly most of our issues are with the definition, but until that is corrected we cannot vote for either.
Response:	Thank you for your comment. 1. A definition of "Component" has been added to the Standard and the Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 2. The dc supply component specifically includes battery chargers within the new Table 1-4.
Segment:	3
Organization:	Public Utility District No. 1 of Chelan County
Member:	Kenneth R. Johnson
Comment:	Comments: 1. It is still unclear whether relays that respond to mechanical inputs, such as sudden pressure relays, are included in the proposed definition as protective relays. While PRC-005-2 R1 limits the scope of that particular standard to protection systems that sense electrical quantities, it is remains unclear in other standards that use the defined term whether mechanical input protections are included. 2. We suggest that "Protective Relay" also be defined, and that the definition clearly exclude devices that respond to mechanical inputs in line with the NERC interpretation of PRC-005-1 in response to the CMPWG request.
Response:	Thank you for your comment. 1. The definition of Protection System has been modified to specifically limit it to protective relays that

	respond to electrical quantities. 2. IEEE has provided a definition of protective relay, and the SDT sees no need to repeat or change that definition within this Standard.
Segment:	3, 3
Organization:	Municipal Electric Authority of Georgia, MEAG Power
Member:	Steven M. Jackson, Steven Grego
Comment:	1. Station DC supply testing was set at three months. A six month time based testing interval is reasonable. 2. Maximum maintenance interval for a lead-acid vented battery is listed at six calendar years. This type of test reduces battery life. A 10 to 12 year interval is reasonable. As written this rule would require a TFE that should be administratively unnecessary. 3. Additional clarification is needed in: Control and trip circuits associated with UVLS and UFLS do not require tripping of the breakers but all other protection systems require tripping. Please clarify. 4. Digital relays have electromagnetic output relays - are they categorized as electromechanical or solid state? 5. There needs to be reasonable flexibility based on industry experience in allowing less than 100% perfection in the testing of relays, etc.
Response:	Thank you for your comment. 1. The SDT disagrees. 2. The SDT disagrees. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-1. 5. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	3, 4, 5
Organization:	Cowlitz County PUD

Member:	Russell A Noble, Rick Syring, Bob Essex
Comment:	Cowlitz agrees with most of the changes; however there are many issues from the last comment round that needs to be addressed with a response from the SDT. In particular, Cowlitz is concerned with the following: 1. Verify Battery cell-to-cell connection resistance" has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting "unit-to-unit" wherever "cell-to-cell" is used in the table now. 2. The level two table regarding Protection Station dc supply states that level one maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don't match those in level one; which activities shall Cowlitz use? Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing. 3. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. Cowlitz suggests changing the maximum interval for battery inspections to six calendar months. For consistency, Cowlitz also suggests that all intervals expressed as three calendar months be changed to six calendar months. 4. Cowlitz is concerned over R1.1, where all components must be identified, without a definition for the word component or the granularity specified. While the FAQ gives a definition, and allows for entity latitude in determining the granularity, the FAQ is not part of the standard. Cowlitz believes this will allow REs to claim non-compliance for every three inch long terminal jumper wire not identified in a trip circuit path. Cowlitz suggests that the FAQ definitions be included within the standard. 5. Many Distribution Providers do not own Protection Systems on the transmission side that are active devices, but rather are passive in nature, i.e., fuses. This Standard verbiage will make it necessary for all DPs

	to have a PSMP even if they do not own active Protective Systems that at least states that they have a null listing of components. This is useless paperwork.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 3. The SDT disagrees. You should complete the activities within the intervals specified. 4. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. 5. Fuses are not a Protection System component. The SDT is not addressing what an entity that owns no relevant components must do to demonstrate that for compliance.
Segment:	3
Organization:	Consumers Energy
Member:	David A. Lapinski
Comment:	1. If multiple redundant Protection System components, with associated parallel tripping paths, are provided, Table 1a, 1b, and 1c require that each parallel path be maintained, and that the maintenance be documented. Often, these multiple schemes are provided not to meet specific reliability-related requirements, but instead to provide operating flexibility. Testing these likely will require outages, and those outages may result in decreased reliability. Further, the documentation related to maintenance of all paths will be very cumbersome, and will lead to increased compliance exposure simply by its volume. This may perversely lead to entities NOT installing the redundant schemes, resulting in decreased reliability. 2. Many of the activities described in the Tables are not, by themselves, clear. The standard should include sufficient detail such that entities are clear as to what must be done for compliance, rather that relying on supplementary documents for this information. For example, it's not clear, in Table 1a (Station DC Supply), what is meant by, "Verify that the dc supply can perform as designed when the ac power from the grid is not present." Similarly, it isn't clear from the general description within the Tables that components possessing different monitoring attributes within a single scheme may be distinguished such that differing relevant tables

	can be used for the separate components. 3. In Table 1a, Station DC Supply, one of two optional activities is to “Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. Battery assemblies supplied by some manufacturers have the connections made internally, making this option unavailable. Experience with ASME standards show that NERC and SDT members may be jointly and separately liable for litigation by specifying methods that either prefer or prohibit use of certain technologies. 4. Two of the four Maintenance Activities that begin with “Perform a complete functional trip …“ conclude with “… does not require actual tripping of circuit breakers or other interrupting devices. Do the other two such activities therefore require tripping of circuit breakers or other interrupting devices? 5. Performance of the minimum activities specified within Table 1a for legacy systems, particularly regarding control circuits, will require considerable disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. We suggest that the SDT reconsider these activities with regard for this concern. 6. We do not agree that Footnotes within the Standard are an appropriate method of providing information that is important to the application of the Standard. Important information should be provided within the standard text.
Response:	Thank you for your comment. 1. The SDT believes that it is important that all parallel paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of parallel tripping paths. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 3. The use of the term “cell/unit” acknowledges that individual cells may not be accessible, but that assemblies of several cells (into units) may be available instead, and may be used to address this requirement. An acceptable baseline value and follow-on tests may be acceptable for the entire station battery as a single unit. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.

	5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. To the degree that performance history for the components within these systems is available, a performance-based program per R3 and Attachment A may be useful in these cases. 6. The SDT removed all footnotes from the Standard.
Segment:	5
Organization:	Consumers Energy
Member:	James B Lewis
Comment:	1. If multiple redundant Protection System components, with associated parallel tripping paths, are provided, Table 1a, 1b, and 1c require that each parallel path be maintained, and that the maintenance be documented. Often, these multiple schemes are provided not to meet specific reliability-related requirements, but instead to provide operating flexibility. Testing these likely will require outages, and those outages may result in decreased reliability. Further, the documentation related to maintenance of all paths will be very cumbersome, and will lead to increased compliance exposure simply by its volume. This may perversely lead to entities NOT installing the redundant schemes, resulting in decreased reliability. 2. Many of the activities described in the Tables are not, by themselves, clear. The standard should include sufficient detail such that entities are clear as to what must be done for compliance, rather that relying on supplementary documents for this information. For example, it's not clear, in Table 1a (Station DC Supply), what is meant by, "Verify that the dc supply can perform as designed when the ac power from the grid is not present." Similarly, it isn't clear from the general description within the Tables that components possessing different monitoring attributes within a single scheme may be distinguished such that differing relevant tables can be used for the separate components. 3. In Table 1a, Station DC Supply, one of two optional activities is to "Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. Battery assemblies supplied by some manufacturers have the connections made internally, making this option unavailable. Experience with ASME standards show that NERC and SDT members may be jointly and separately liable for litigation by specifying methods that either prefer or prohibit use of certain technologies. 4. Two of the four Maintenance Activities that begin with "Perform a complete functional trip …" conclude with "… does not require actual tripping of circuit breakers or other interrupting devices. Do the other two

	such activities therefore require tripping of circuit breakers or other interrupting devices? 5. Performance of the minimum activities specified within Table 1a for legacy systems, particularly regarding control circuits, will require considerable disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. We suggest that the SDT reconsider these activities with regard for this concern. 5. We do not agree that Footnotes within the Standard are an appropriate method of providing information that is important to the application of the Standard. Important information should be provided within the standard text. 6. As for the definition, it is unclear whether “voltage and current sensing inputs” include the instrument transformer itself, or does it pertain to only the circuitry and input to the protective relays. 7. As for the definition, it is not clear what is included in the component, “station dc supply” without referring to other documents (the posted Supplementary Reference and/or FAQ) for clarification. The definition should be sufficiently detailed to be clear. 8. If Protection Systems trip via AC methods, are those systems and the associated control circuitry included in the definition and within the requirements of the Standard as expressed within the Tables?
Response:	Thank you for your comment. 1. The SDT believes that it is important that all parallel paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of parallel tripping paths. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 3. The use of the term “cell/unit” acknowledges that individual cells may not be accessible, but that assemblies of several cells (into units) may be available instead, and may be used to address this requirement. An acceptable base-line value and follow-on tests may be acceptable for the entire station battery as a single unit. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.

	5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. To the degree that performance history for the components within these systems is available, a performance-based program per R3 and Attachment A may be useful in these cases. 6. The SDT removed all footnotes from the Standard. 7. The SDT removed all footnotes from the Standard. 8. “Control circuitry” has been revised to remove “dc” to generalize it such that “ac” tripping would be included.
Segment:	4
Organization:	Consumers Energy
Member:	David Frank Ronk
Comment:	1. If multiple redundant Protection System components, with associated parallel tripping paths, are provided, Table 1a, 1b, and 1c require that each parallel path be maintained, and that the maintenance be documented. Often, these multiple schemes are provided not to meet specific reliability-related requirements, but instead to provide operating flexibility. Testing these likely will require outages, and those outages may result in decreased reliability. Further, the documentation related to maintenance of all paths will be very cumbersome, and will lead to increased compliance exposure simply by its volume. This may perversely lead to entities NOT installing the redundant schemes, resulting in decreased reliability. 2. Many of the activities described in the Tables are not, by themselves, clear. The standard should include sufficient detail such that entities are clear as to what must be done for compliance, rather that relying on supplementary documents for this information. For example, it’s not clear, in Table 1a (Station DC Supply), what is meant by, “Verify that the dc supply can perform as designed when the ac power from the grid is not present.” Similarly, it isn’t clear from the general description within the Tables that components possessing different monitoring attributes within a single scheme may be distinguished such that differing relevant tables can be used for the separate components. 3. In Table 1a, Station DC Supply, one of two optional activities is to “Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. Battery assemblies supplied by some manufacturers have the connections made internally, making this option unavailable. Experience with ASME standards show that NERC and SDT members may be jointly and

	separately liable for litigation by specifying methods that either prefer or prohibit use of certain technologies. 4. Two of the four Maintenance Activities that begin with "Perform a complete functional trip …"conclude with "… does not require actual tripping of circuit breakers or other interrupting devices. Do the other two such activities therefore require tripping of circuit breakers or other interrupting devices? 5. Performance of the minimum activities specified within Table 1a for legacy systems, particularly regarding control circuits, will require considerable disconnection and reconnection of portions of the circuits. Such activities will likely cause far more problems on restoration-to-service than they will locate and correct. We suggest that the SDT reconsider these activities with regard for this concern. 6. In the Standard, Footnote 2 and Footnote 3 are identical. We presume that some information has been omitted. 7. We do not agree that Footnotes are an appropriate method of providing information that is important to the application of the Standard. Important information should be provided within the standard text.
Response:	Thank you for your comment. 1. The SDT believes that it is important that all parallel paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of parallel tripping paths. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. 3. The use of the term "cell/unit" acknowledges that individual cells may not be accessible, but that assemblies of several cells (into units) may be available instead, and may be used to address this requirement. An acceptable base-line value and follow-on tests may be acceptable for the entire station battery as a single unit. 4. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. To the degree that performance history for the components within these systems is available, a performance-based program per R3 and Attachment A may be useful in these cases.

	6. The SDT removed all footnotes from the Standard. 7. The SDT removed all footnotes from the Standard.
Segment:	3
Organization:	City of Bartow, Florida
Member:	Matt Culverhouse
Comment:	The draft standard requires testing and maintenance on DC circuits of distribution systems that have no effect on the reliability of the BES which we feel is outside of the bounds of the original intent of NERC.
Response:	Thank you for your comment. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
Segment:	2
Organization:	Midwest ISO, Inc.
Member:	Jason L Marshall
Comment:	We are abstaining because a number of our stakeholders do not agree with the definition of Protection Systems and inclusion of UFLS and UVLS in a standard dealing with maintenance of protection systems.
Response:	Thank you for your comment. FERC Order 693 suggests combining these Standards, as does the approved SAR for this project. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4 and 1-5 for the constrained activities regarding UFLS and UVLS.
Segment:	8
Organization:	Roger C Zaklukiewicz
Member:	Roger C Zaklukiewicz
Comment:	There in insufficient clarity on the Protection System components that are considered Transmission Protection System equipment which require a Distribution Provider (DP) to perform the required maintenance and testing to ensure compliance with the Standard. In certain distribution substations, components of the high voltage source that supply the distribution substation may be considered components of the Electric Bulk System and their associated protection and control systems must be specified, installed, maintained and tested in accordance with the Standard. Clear delineation of Transmission Protection Systems is therefore critical to ensure the reliability of the EPS.

Response:	Thank you for your comment. This is properly a concern regarding your regional BES definition, and the SDT is unable to respond to these concerns.
Segment:	10
Organization:	Northeast Power Coordinating Council, Inc.
Member:	Guy V. Zito
Comment:	1. There is not enough clarity on whether a Distribution Provider (DP) will be able to clearly identify which protection system components it does own and needs to maintain. Many DPs own and/or operate equipment identified in the existing or proposed definition. However, not all such equipment translates into a transmission Protection System. The definition needs clarification on when such equipment is a part of the transmission protection system. 2. Also, the time provided for the first phase "at least six months" is too open ended and does not provide entities with a clear timeline. It is suggested that one year is appropriate for the first phase phasing out the second year in stages. 3. Regarding battery visuals, the suggestion for consideration is it should be changed from 3 months to 6 months. Electrolyte levels of today's lead-calcium batteries are relatively stable for a 6 month period compared to lead-antimony batteries used in the past. 4. The Implementation plan is too short - In many instances it will be impossible to meet, especially if entities have to create, purchase and adopt new databases to track maintenance activities. Often new procedures will have to be written and additional resources justified and hired. It would be more acceptable if a staged approached was taken similar to the DME Standard. 5. Accounting for every component of a protection system will be an enormous overhead and will take away resources from actually doing maintenance. Emphasis should be on systems and not individual components. 6. The Standard does not provide a grace period if an entity is unable to meet the maintenance requirement for extenuating circumstances. For example if an entity has to divert maintenance resources to storm restoration following a major event, slack built into a maintenance program can be eaten up and put the maintenance over the prescribed period. Provision should be made for a mitigation plan to get back on track. We do not believe the reliability of the Bulk Electric System will be compromised if an entities' maintenance

	program slips by a few months due to extreme contingencies, especially if it is brought back on track within a short time frame.
Response:	Thank you for your comment. 1. This is an issue related to the regional BES definition, and the DP needs to consider their equipment in the context of this definition. 2. This comment appears to be related to the Implementation Plan for the definition (which was independent to the Standard), not to the Standard. 3. The SDT disagrees; these activities should be completed as prescribed in the Standard. 4. A staged Implementation Plan is provided for all activities that have prescribed maximum allowable intervals over one year. However, the SDT believes that a staged Implementation Plan for developing the PSMP is impractical, in that an entity cannot reasonably implement a plan until they have developed it. 5. The SDT believes that the only alternative to these criteria is to provide a binary VSL, which would mean that any non-compliance would be Severe. A definition of Component and Component Types have been added to the Standard, and Requirement R1, part 1.1, has been revised to state, “Address all Protection System component types” to assist in this task. 6. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard.
Segment:	1, 3
Organization:	Hydro One Networks, Inc.
Member:	Ajay Garg, Michael D. Penstone
Comment:	Hydro One is casting a negative vote for the following reasons: 1. There is not enough clarity on whether a Distribution Provider (DP) will be able to clearly identify which protection system components it does own and needs to maintain. Many DPs own and/or operate equipment identified in the existing or proposed definition. However, not all such equipment translates into a transmission Protection System. 2. The proposed definition of Protection System needs clarification on when such equipment is a part of

	the transmission protection system. Emphasis should be on systems and not individual components. 3. The time provided for the first phase "at least six months" is too open ended and does not provide entities with a clear timeline. It would be more acceptable if a staged approach was taken. 4. The Standard does not provide a grace period if an entity is unable to meet the maintenance requirement for extenuating circumstances. For example if an entity has to divert maintenance resources to storm restoration following a major event, slack built into a maintenance program can be eaten up and put the maintenance over the prescribed period. Provision should be made for a mitigation plan to get back on track. We do not believe the reliability of the Bulk Electric System will be compromised if an entities' maintenance program slips by a few months due to extreme contingencies, especially if it is brought back on track within a short time frame. 5. Table 1a: UFLS/UVLS DC control and trip circuits – Due to the distributed nature of this program, random failures to trip are not impactive to the overall operation of the UFLS protection. There should be no requirement to check the DC portion of these protections any more often than the DC circuit checks associated with that LV breaker. 6. Table 1c: some of the proposed maintenance intervals for station DC supply are too stringent and they would not produce significant increase in reliability to justify associated incremental expenditure.
Response:	Thank you for your comment. 1. This is an issue related to the regional BES definition, and the DP needs to consider their equipment in the context of this definition. 2. This is an issue related to the regional BES definition, and the DP needs to consider their equipment in the context of this definition. It seems that Protection Systems logically need to be maintained on a Component level; definitions of Component and Component Type have been added to assist. 3. This comment appears to be related to the Implementation Plan for the definition (which was independent to the Standard), not to the Standard. 4. “Grace periods” within the Standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the Standard. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table

	1-5 for constrained activities related to UFLS/UVLS. 6. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4.
Segment:	1, 1, 3, 6
Organization:	Consolidated Edison Co. of New York, Northeast Utilities, Consolidated Edison Co. of New York, Consolidated Edison Co. of New York
Member:	Christopher L de Graffenried, David H. Boguslawski, Peter T Yost, Nickesha P Carrol
Comment:	1. There is not enough clarity on whether a Distribution Provider (DP) will be able to clearly identify which protection system components it does own and needs to maintain. Many DPs own and/or operate equipment identified in the existing or proposed definition. However, not all such equipment translates into a transmission Protection System. The definition needs clarification on when such equipment is a part of the transmission protection system. 2. Also, the time provided for the first phase "at least six months" is too open ended and does not provide entities with a clear timeline. It is suggested that one year is appropriate for the first phase phasing out the second year in stages.
Response:	Thank you for your comment. 1. This is an issue related to the regional BES definition, and the Distribution Provider needs to consider their equipment in the context of this definition. 2. This comment appears to be related to the Implementation Plan for the definition (which was independent to the Standard), not to the Standard.
Segment:	3
Organization:	Allegheny Power
Member:	Bob Reeping
Comment:	The draft standard expects 100% compliance for millions of protection system components at all times. The standard should consider a statistically based performance metric instead of a performance target that expects 100% compliance.
Response:	Thank you for your comment. The NERC criteria for VSLs do not currently permit them to allow some level

	of non-performance without being in violation.
Segment:	1, 1, 3, 6
Organization:	Keys Energy Services, Lakeland Electric, Lakeland Electric, Florida Municipal Power Pool
Member:	Stan T. Rzad, Larry E Watt, Mace Hunter, Thomas E Washburn
Comment:	1. As written, is opens up the PRC-005 standard to Technical Feasibility Exceptions because some batteries are not able to accommodate all of the tests proscribed in the draft standard. 2. The draft standard would cause NERC to regulate through the standards battery testing, DC circuit testing, etc. on distribution elements with no significant improvement to BES reliability, which is beyond the statutory scope of the standards 3. The standard unreasonably retains the "100% compliance" paradigm for thousands, if not millions of protection system components.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. 2. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system. 3. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	1
Organization:	Gainesville Regional Utilities
Member:	Luther E. Fair
Comment:	1. As written, is opens up the PRC-005 standard to Technical Feasibility Exceptions because some batteries are not able to accommodate all of the tests proscribed in the draft standard as explained by Steve Alexanderson in a prior e-mail to the ballot pool. 2. The draft standard would cause NERC to regulate through the standards battery testing, DC circuit testing,

	etc. on distribution elements with no significant improvement to BES reliability, which is beyond the statutory scope of the standards. 3. The standard unreasonably retains the "100% compliance" paradigm for thousands, if not millions of protection system components. These comments are the same as provided by FMPA which we support.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. 2. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system. 3. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	1, 4, 5
Organization:	Lake Worth Utilities, Florida Municipal Power Agency, Florida Municipal Power Agency
Member:	Walt Gill, Frank Gaffney, David Schumann
Comment:	1. As written, is opens up the PRC-005 standard to Technical Feasibility Exceptions because some batteries are not able to accommodate all of the tests proscribed in the draft standard 2. The draft standard would cause NERC to regulate through the standards battery testing, DC circuit testing, etc. on distribution elements with no significant improvement to BES reliability, which is beyond the statutory scope of the standards 3. The standard unreasonably retains the "100% compliance" paradigm for thousands, if not millions of protection system components. 4. Will the Standard Introduce Technical Feasibility Exceptions to PRC Standards? A large proportion of the batteries (as high as 50% as reported by some SMEs) are not able to accommodate all of the tests prescribed in the draft standard. Will this necessitate the introduction of TFEs into the process unnecessarily? 5. The Standard Reaches beyond the Statutory Scope of the Reliability Standards As written, the

	standard requires testing of batteries, DC control circuits, etc., of distribution level protection components associated with UFLS and UVLS. UFLS and UVLS are different than protection systems used to clear a fault from the BES. An uncleared fault on the BES can have an Adverse Reliability Impact and hence; the focus on making sure the fault is cleared is important and appropriate. However, a UFLs or UVLS event happens after the fault is cleared and is an inexact science of trying to automatically restore supply and demand balance (UFLS) or restore voltages (UVLS) to acceptable levels. If a few UFLS or UVLS relays fail to operate out of potentially thousands of relays with the same function, there is no significant impact to the function of UFLS or UVLS. Hence, there is no corresponding need to focus on every little aspect of the UFLS or UVLS systems. Therefore, the only component of UFLS or UVLS that ought to be focused on in the new PRF-005 standard is the UFLS or UVLS relay itself and not distribution class equipment such as batteries, DC control circuitry, etc., and these latter ought to be removed from the standard. 6. In addition, most distribution circuit are radial without substation arrangements that would allow functional testing without putting customers out of service while the testing was underway, or at least without momentary outages while customers were switched from one circuit to another. Therefore, as written, we would be sacrificing customer service for a negligible impact on BES reliability. 7. Perfection is Not A Realistic Goal The standard allows no mistakes. Even the famous six sigma quality management program allows for defects and failures (i.e., six sigma is six standard deviations, which means that statistically, there are events that fall outside of six standard deviations). PRC-005 has been drafted such that any failure is a violation, e.g., 1 day late on a single relay test of tens of thousands of relays is a violation. That is not in alignment with worldwide accepted quality management practices (and also makes audits very painful because statistical, random sampling should be the mode of audit, not 100% review as is currently being done in many instances). FMPA suggests considering statistically based performance metrics as opposed to an unrealistic performance target that does not allow for any failure ever. Due to the sheer volume of relays, with 100% performance required, if the standards remain this way, PRC-005 will likely be in the top ten most violated standards for the forever. There is a fundamental flaw in thinking about reliability of the BES. We are really not trying to eliminate the risk of a widespread blackout; we are trying to reduce the risk of a widespread blackout. We plan and operate the system to single and credible double contingencies and to finite operating and planning reserves. To eliminate the risk, we would need to plan and operate to an infinite number of contingencies, and have an infinite reserve margin, which is infeasible. Therefore, by definition, there is a finite risk of a widespread blackout that we are trying to reduce, not eliminate, and, by definition, by planning and operating to single and credible double

	contingencies and finite operating and planning reserves, we are actually defining the level of risk from a statistical basis we are willing to take. With that in mind, it does not make sense to require 100% compliance to avoid a smaller risk (relays) when we are planning to a specified level of risk with more major risk factors (single and credible double contingencies and finite planning and operating reserves).
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. 2. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system. 3. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. 4. No. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. 5. The Standard only addresses distribution-located devices to the degree that they address BES issues. UFLS and UVLS per the relevant NERC Standards are frequently implemented on the distribution system. 6. The Standard does not require functional testing, although it may be the most practical method of completing some of the required activities. There are other methods, too, of completing these. 7. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
Segment:	4
Organization:	Illinois Municipal Electric Agency
Member:	Bob C. Thomas
Comment:	IMEA is supportive of the intent of PRC-005-2; however, based on monitoring of comments submitted to date, IMEA would like to see concerns addressed before voting to affirm this proposed standard revision. IMEA supports the comments expressed during ballot pool communications that provisions need to be included to avoid the possible necessity of having to use the burdensome TFE process and to avoid the

	unrealistic expectation of perfection in recordkeeping and exactness of maintenance schedule dates.
Response:	Thank you for your comment. Responses have been provided to the various ballot comments.
Segment:	1
Organization:	Georgia Transmission Corporation
Member:	Harold Taylor, II
Comment:	The SDT has made significant changes to the minimum maintenance activities and maximum allowable intervals within Tables 1a, 1b, and 1c, particularly related to station dc supply and dc control circuits. Do you agree with these changes? If not, please provide specific suggestions for improvement. Comments: 1. Do not agree with the 3 calendar months interval and suggest using quarterly. Both terms require a minimum of four inspections per year have proven to be successful, but the term "quarterly" provides a bit more flexibility than the term "3 calendar months". Given a 3 month maximum interval an entity would need to schedule these tasks every 2 months. 2. As the current requirements are written in R1 of PRC-005-2 Draft, we disagree with the terms identify all Protection System components. We recommend a less prescriptive requirement as listed below. R1.1 Identify BES substations or facilities containing Protection Systems. R1.2 Identify whether Protection Systems per substation or facilities are addressed through time-based, condition-based, performance based or a combination based etc. R1.3 For each substation/facility with Protection Systems include all maintenance activities etc. 3. Listing each individual Protection System component as current draft is onerous and impedes any interpretation of application with very little value. 4. The standard as written will require a great deal of effort by the utilities to maintain 100% compliance as listed. The concern is the power system design allows for some contingencies but the standard allows for no errors. Failing to complete 1% of the maintenance by 1 day infers an entity is out of compliance or in violation. The violations should start for more than a level of 5% not identified, or not maintained. 5. We feel the minor changes of wording as described in R1.1 – R1.3 as listed above will go a long way in

	removing the concerns of the standard. We feel the intent of the standard is sound and request minor changes to facilitate an interpretable standard that sensibly mitigates problems with the BES. As the standard written, the interpretation seems to create a stringent environment with undue compliance requirements. 6. Lastly, the SDT should attempt to embrace Gerry Cauley's vision of "results-based standards" and clearly identify the "risk mitigation objectives, reliability result or outcome" of the revised requirements and allow each entity to meet the outcome and mitigate the risk without writing in such a prescriptive manner which is not preferred. The prescriptive details currently proposed in the standard could then be captured in a reference document.
Response:	Thank you for your comment. 1. The SDT disagrees. Once per calendar quarter would allow up to six months between inspections, while three calendar months limits the effective interval to four months (minus 2 days). 2. Modifying Requirement R1 as you suggest would make it so general that it would be difficult to measure for compliance. Additionally, because of the variety of types of component within a substation, it may be difficult to define a substation-wide (or facility-wide) PSMP that addresses all components and intervals. A definition of Component has been added to the Standard, and Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types". 3. A definition of Component has been added to the Standard to assist; also, Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. 4. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. 5. As noted above, the SDT believes that Requirement R1 would no longer be measurable. 6. The SDT agrees that the SDT may effectively embrace the "results-based" approach within this Standard; however, doing so at this time would delay development of this high-priority Standard. This is reflected on pages 13-14 of the current draft Standards Development Plan that is out for comment at this time.
Segment:	3, 4
Organization:	Georgia System Operations Corporation
Member:	R Scott S. Barfield-McGinnis, Guy Andrews

Comment:	1. Do not agree with the 3 calendar months interval and suggest using quarterly. Both terms require a minimum of four inspections per year have proven to be successful, but the term “quarterly” provides a bit more flexibility than the term “3 calendar months”. Given a 3 month maximum interval an entity would need to schedule these tasks every 2 months. 2. As the current requirements are written in R1 of PRC-005-2 Draft, we disagree with the terms identify all Protection System components. We recommend a less prescriptive requirement as listed below. -R1.1 Identify BES substations or facilities containing Protection Systems. -R1.2 Identify whether Protection Systems per substation or facilities are addressed through time-based, condition-based, performance based or a combination based etc. -R1.3 For each substation/facility with Protection Systems include all maintenance activities etc. 3. The VRF for R1 ranking should be lower or no greater than R2, R3, and R4. The task of identifying Protection System components has very little to do with increasing reliability of the BES. The implementation of the PSMP most likely will cover all the specific functions of Protection System components although the entity failed to identify all PS components. We recommend the above language changes and agree the requirement adds some value but not a high-risk value to the BES. 4. After correcting the language we feel that a requirement of 100% maintenance on 100% of all components as listed on page 6 of the standard for the VSLs leaves no room for error for systems designed with contingences. The violations should start for more than a level of 5% not identified, not maintained, etc. 5. Listing each individual Protection System component as current draft is onerous and impedes any interpretation of application with very little value. The standard as written will require a great deal of effort by the utilities to maintain 100% compliance as listed. The concern is the power system design allows for some contingencies but the standard allows for no errors. Failing to complete 1% of the maintenance by 1 day infers an entity is out of compliance or in violation. The violations should start for more than a level of 5% not identified, or not maintained. 6. We feel the minor changes of wording as described in R1.1 – R1.3 as listed above will go a long way in removing the concerns of the standard. We feel the intent of the standard is sound and request minor changes to facilitate an interpretable standard that sensibly mitigates problems with the BES. As the standard written, the interpretation seems to create a stringent environment with undue compliance requirements.

	7. Lastly, the SDT should attempt to embrace Gerry Cauley's vision of "results-based standards" and clearly identify the "risk mitigation objectives, reliability result or outcome" of the revised requirements and allow each entity to meet the outcome and mitigate the risk without writing in such a prescriptive manner which is not preferred. The prescriptive details currently proposed in the standard could then be captured in a reference document.
Response:	Thank you for your comment. 1. The SDT disagrees. Once per calendar quarter would allow up to six months between inspections, while three calendar months limits the effective interval to four months (minus 2 days). 2. Modifying Requirement R1 as you suggest would make it so general that it would be difficult to measure for compliance. Additionally, because of the variety of types of component within a substation, it may be difficult to define a substation-wide (or facility-wide) PSMP that addresses all components and intervals. A definition of Component has been added to the Standard, and Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types". 3. The VRFs have been revised. 4. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. 5. A definition of Component has been added to the Standard to assist; also, Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. 6. As noted above, the SDT believes that Requirement R1 would no longer be measurable. 7. The SDT agrees that the SDT may effectively embrace the "results-based" approach within this Standard; however, doing so at this time would delay development of this high-priority Standard. This is reflected on pages 13-14 of the current draft Standards Development Plan that is out for comment at this time.
Segment:	1, 3, 6
Organization:	FirstEnergy Energy Delivery, FirstEnergy Solutions, Kevin Querry
Member:	Robert Martinko, Kevin Querry, Mark S Travaglianti
Comment:	Please see FE comments for suggested enhancements submitted via the parallel comment period for this standard.

Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1, 3, 5, 6
Organization:	Entergy Corporation, Entergy, Entergy Corporation, Entergy Services, Inc.
Member:	George R. Bartlett, Joel T Plessinger, Stanley M Jaskot, Terri F Benoit
Comment:	The following are the reasons associated with our Negative Ballot. 1. Table 1a contains "Type of Protection System Component" entry "Control and trip circuits with electromechanical trip or auxiliary contacts (except for microprocessor relays, UFLS or UVLS)". However, there is no Component entry for the exception (except for microprocessor relays, UFLS or UVLS). Please add a Component entry with associated intervals and activities for: "Control and trip circuits with electromechanical trip or auxiliary contacts" with a microprocessor relay application. 2. The term "check" has replaced "verify" for some maintenance activities. Replace "verify" with "check" in all locations in the Tables. 3. Redefine "verification" to "A means of determining or checking that the component is functioning properly or maintenance correctable issues are identified". 4. We support this project and believe it is a positive step towards BES reliability. However, we believe the draft document needs additional work as per our comments. Also, as indicated by the amount of industry input on the last version draft comments, we believe revisions are still needed to properly address this technically complex standard. 5. If this standard is to deviate from the original project schedule and follow a fast track timeline for approval, then we disagree with the 3 month implementation for Requirement 1 and ask for at least 12 months. The original schedule provided sufficient advance notice to work on an implementation plan and it included the typical time required for NERC Board of Trustees and regulatory approvals. If the project schedule and typical NERC Board of Trustees and regulatory approval times are to be accelerated, the implementation plan should be extended. We reserve the right to include selected reasons submitted by other Negative balloters for their Negative Ballot.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table

	1-5. 2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5. 3. “Check” is not an element of the PSMP definition. This term, throughout the tables, has been replaced with whatever term of the definition is relevant. 4. Thank you. 5. The Implementation Plan for Requirement R1 has been revised from three months to twelve months.
Segment:	1
Organization:	Empire District Electric Co.
Member:	Ralph Frederick Meyer
Comment:	It is still unclear whether relays that respond to mechanical inputs, such as sudden pressure relays, are included in the proposed definition as protective relays. While PRC-005-2 R1 limits the scope of that particular standard to protection systems that sense electrical quantities, it is remains unclear in other standards that use the defined term whether mechanical input protections are included. We suggest that “Protective Relay” also be defined, and that the definition clearly exclude devices that respond to mechanical inputs in line with the NERC interpretation of PRC-005-1 in response to the CMPWG request.
Response:	Thank you for your comment. The Protection System definition has been revised to explicitly include only protective relays that respond to electrical quantities. This definition applies to all uses of this term within NERC Standards. The SDT feels that the IEEE definition of protective relay is adequate and sees no need to either repeat or change that definition.
Segment:	1
Organization:	Colorado Springs Utilities
Member:	Paul Morland
Comment:	CSU offers the following comments: With BES still not defined it is difficult to determine what the standard applies to. Requirements are confusing at times, making the standard difficult to audit.
Response:	Thank you for your comment. This concern is a BES concern, and the SDT is unable to address or resolve it.
Segment:	1

Organization:	Avista Corp.
Member:	Scott Kinney
Comment:	Avista has the following comments: 1. The modified definition of Protection System now refers to “functions” rather than “devices.” What are the “functions?” This new term adds confusion without being defined in the standard. 2. Considering all the time spent by Regional Entities and utilities discussing what is meant by monthly, quarterly, annual, etc., this standard should clearly define a Calendar Year and Calendar Month to eliminate any confusion. 3. In general, the requirements of the Standard are very prescriptive and granular which seem counter to the newly adopted NERC philosophy of implementing “performance-based” or “results-based” standards. Specifically, the relay testing requirements are very extensive and not entirely practical when it comes to conducting actual breaker tripping for testing. Also, there are now different maintenance and testing requirements for station batteries depending on the type of battery in service. What’s the real added reliability to the BES to add this complexity to the maintenance program? Considering these observations, is there some real historical research that has gone into determining these requirements? In general, how did the drafting team arrive at the maximum allowable maintenance and testing intervals for inclusion in the Standard, i.e., what is the technical basis for their decisions regarding this?
Response:	Thank you for your comment. 1. “Functions” acknowledge that, while protective relays (or protective devices) is the most common implementation, other devices are now used (particularly in SPSs) that provide these functions from other than traditional relays. 2. A “calendar year” is a single number year on the Gregorian calendar; a calendar month is any one of the twelve months within a single calendar year. Please see Section 8.3 of the Supplementary Reference document. 3. Please see Section 8.3 of the Supplemental Reference document for a discussion of the determination of relay and communications system intervals. For the other components, the SDT studied other sources such as IEEE standard, EPRI documents, visited with various industry experts (such as within IEEE), conducted informal surveys of existing practices, and adjusted to conform to concerns such as generator outage intervals.
Segment:	3

Organization:	Central Lincoln PUD
Member:	Steve Alexanderson
Comment:	1. The SDT has made significant changes to the minimum maintenance activities and maximum allowable intervals within Tables 1a, 1b, and 1c, particularly related to station dc supply and dc control circuits. Do you agree with these changes? If not, please provide specific suggestions for improvement. 0 Yes X No Comments: We agree with most of the changes from the last draft. However, the phrase "Verify Battery cell-to-cell connection resistance" has entered the table where it did not exist before. On some types of stationary battery units, this internal connection is inaccessible. On other types the connections are accessible, but there is no way to repair them based on a bad reading. And bad cell-to-cell connections within units will be detected by the other required tests. This requirement will cause entities to scrap perfectly good batteries just so this test can be performed, with no corresponding increase in bulk electric system reliability while taking an unnecessary risk to personnel and the environment. And because buying battery units composed of multiple cells allows space saving designs, entities may be forced to buy smaller capacity batteries to fit existing spaces. This may end up having a negative effect on reliability. Suggest substituting "unit-to-unit" wherever "cell-to-cell" is used in the table now. 2. The SDT has included VRFs and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for improvement. X Yes 0 No Comments: 3. The SDT has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for improvement. X Yes 0 No Comments: 4. The SDT has included VSLs with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change. 0 Yes X No Comments: It is possible that a component that failed to be individually identified per R1.1 was included by entity A's maintenance plan. This documentation issue gets a higher VSL than entity B that identified a component without maintaining it. We suggest the R1 VSL be change to Low, since we believe lack of maintenance to be more severe than documentation issues. 5. The SDT has revised the "Supplementary Reference" document which is supplied to provide supporting discussion for the Requirements within the standard. Do you agree with the changes? If not, please provide

	specific suggestions for change. X Yes 0 No Comments: 6. The SDT has revised the “Frequently-Asked Questions” (FAQ) document which is supplied to address anticipated questions relative to the standard. Do you agree with these changes? If not, please provide specific suggestions for change. X Yes 0 No Comments: 7. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here. Comments: The level 2 table regarding Protection Station dc supply states that level 1 maintenance activities are to be used, but then goes on to give a list of Maintenance Activities that don’t match those in level 1. Which activities shall we use? 8. Same situation for Station DC Supply (battery is not used) where the 18 month interval is missing. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months. 9. We are concerned over R1.1, where all components must be identified, without a definition for the word component or the granularity specified. While the FAQ gives a definition, and allows for entity latitude in determining the granularity, the FAQ is not part of the standard. We believe this will allow REs to claim non-compliance for every three inch long terminal jumper wire not identified in a trip circuit path. We suggest that the FAQ definitions be included within the standard.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, “Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)” to address this comment. 2. Thank you. 3. Thank you. 4. Requirement R1, part 1.1, has been revised to state, “Address all Protection System component types” and the VSL for Requirement R1 modified in consideration of your comment.

	5. Thank you. 6. Thank you. 7. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. 8. The SDT disagrees; the components should be maintained as specified within the new tables. 9. Requirement R1, part 1.1, has been revised to state, "Address all Protection System component types" in consideration of your comment. Definitions were also added to the Standard for Component Type and Component.
Segment:	3, 5, 6
Organization:	Lincoln Electric System
Member:	Bruce Merril, Dennis Florom, Eric Ruskamp
Comment:	LES would like to thank the Drafting Team for its time and effort in developing the standard. However, the standard as currently drafted raises concern as it relates to the identification of all Protection System components. LES asks the Drafting Team to further examine the impact of implementing such a rigorous maintenance program that could potentially impose unnecessary burden and reliability risk with an overly prescriptive approach. Redundancy has been implemented in great detail throughout the history of protection systems to ensure they function as intended. In addition to the comments submitted through the MRO NSRS group comment form, LES would like to further emphasize the following points of contention: (1) Consider revising to consider maintenance activities on a communications channel basis in which intermediate device functioning can be verified by sending a signal from one relay to another. (2) R1, the statement "or are designed to provide protection for the BES" re-opens the argument about transformer protection or breaker failure protection for transformer high-side breakers tripping BES breakers being included in transmission protection systems. (3) Table 1b "breaker trip coil, each auxiliary relay, and each lockout relay" should be changed from a 6 to 12 year interval similar to relay input and outputs. Experience has shown that these both have similar reliability. (4) Include a detailed example of an Inventory List for voltage and current sensing input. (5) Remove "proper functioning of" from the maintenance activities for voltage and current sensing inputs.

	One is not verifying the functionality of the signals. (6) Clarify why control circuitry is stated separately such as in “Control and trip circuits”. This implies that close circuit DC paths are not subjects a PSMP when reclosing and closing of breakers have never before been considered part of a Protection System.
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-2. Functional end-to-end testing would be one method of completing the necessary verification. 2. This is an issue regarding your regional BES definition, and this SDT is unable to resolve such issues. 3. The SDT believes that mechanical solenoid-operated devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 4. The SDT does not understand this comment. The Protection System definition has been changed; perhaps this will help. 5. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-3. **6.** This component of the definition is stated to apply as “associated with protective functions” and thus excludes close/reclosing circuits. Please see FAQ II.1.A.
Segment:	4
Organization:	Madison Gas and Electric Co.
Member:	Joseph G. DePoorter
Comment:	1. The six implementation plan is too quick for some entities. A 1 year implementation is recommended. 2. With the addition of all UFLS in this standard, it is implied battery testing, DC circuit testing, etc. on distribution elements are part of the BES. This may lead to every wire and component to be classified as being a part of the BES.
Response:	Thank you for your comment. 1. This comment appears to be focused on the Implementation Plan for the definition, not for the Standard.

	2. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-4 and 1-5 for simplified maintenance activities relevant to UFLS.
Segment:	8
Organization:	SPS Consulting Group Inc.
Member:	Jim R Stanton
Comment:	1. I share the concerns expressed by FMPA that the overly prescriptive battery testing requirements will require a TFE process that would be tedious to manage. The standard goes far beyond the scope of Reliability Standards to protect the BES. Reliability Standards should state "what" needs to be done, not "how" to do it. Such overly prescriptive requirements blunt the development of superior and more efficient processes by the industry. 2. Table 1a column "Maintenance Activity" should be renamed "Suggested Maintenance Activity". 3. Tables 1a, b, and c should be reference documents and not referred to in the Requirements. This is especially true since we find terms like "where applicable" and "physical condition" in the tables that forces the Registered Entity to make judgment calls that may not align with the judgment of the auditors. This will mean more interpretation requests and will make the standard extremely difficult to audit as the Registered Entities and auditors compare their "judgments."
Response:	Thank you for your comment. 1. The Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-4. This element of the table has been modified to state, "Battery internal cell-to-cell or unit-to-unit connection resistance (where available to measure)" to address this comment. The SDT has prescribed "what," not "how," except for those rare cases where it is necessary to specify both. 2. The "activities" in the Tables are required, not suggested. 3. The Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5. These Tables are made requirements by incorporation within Requirement R4, part 4.1, and therefore are not reference documents. They are created in response to FERC Order 693 and the approved SAR which assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	10
Organization:	Midwest Reliability Organization

Member:	Dan R. Schoenecker
Comment:	“The MRO’s NERC Standards Review Subcommittee believes the proposed implementation plan for R1 is unreasonably short. It proposes that: “Entities shall be 100% compliant on the first day of the first calendar quarter three months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter six months following Board of Trustees adoption.” We believe the implementation periods should be expanded to twice what was proposed in the implementation plan due to the sheer volume of equipment that will need to meet compliance. Thus, we propose an alternate implementation plan for requirement R1, “Entities shall be 100% compliant on the first day of the first calendar quarter six months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption.”
Response:	Thank you for your comment. The Implementation Plan for Requirement R1 has been modified from three months to twelve months in consideration of your comment.
Segment:	4
Organization:	Alliant Energy Corp. Services, Inc.
Member:	Kenneth Goldsmith
Comment:	The Implementation Plan is unreasonably short, for the number of assets. The time period should be doubled to be more practicable.
Response:	Thank you for your comment. The Implementation Plan for Requirement R1 has been modified from three months to twelve months in consideration of your comment.
Segment:	1, 3, 5, 6
Organization:	Manitoba Hydro
Member:	Michelle Rheault, Greg C Parent, Mark Aikens, Daniel Prowse
Comment:	The proposed timelines are not reasonable. See submitted comments.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	10
Organization:	Western Electricity Coordinating Council
Member:	Louise McCarren

Comment:	Lack of clarity or apparent conflict between certain requirements would make compliance assessment difficult.
Response:	Thank you for your comment.
Segment:	1
Organization:	Clark Public Utilities
Member:	Jack Stamper
Comment:	My negative vote reflects the ambiguity and over-stepping issues discussed in many of the comments.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1, 3, 5, 6
Organization:	Kansas City Power & Light Co.
Member:	Michael Gammon, Charles Locke, Scott Heidtbrink, Thomas Saitta
Comment:	The proposed changes in the Standard are far too prescriptive and do not take into account the multitude of manufacturers equipment by establishing broad maintenance cycles and testing intervals.
Response:	Thank you for your comment.
Segment:	1
Organization:	Public Utility District No. 1 of Chelan County
Member:	Chad Bowman
Comment:	The requirements are confusing and at times seem to be in conflict with or duplicative of other requirements. From a compliance perspective, this confusion would make the standard difficult to interpret for compliance and audit purposes.
Response:	Thank you for your comment. The Requirements and Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.
Segment:	3
Organization:	Wisconsin Public Service Corp.
Member:	Gregory J Le Grave
Comment:	The standard and associated definitions as written are too vague, which leave room for varying interpretation.

Response:	Thank you for your comment. The Requirements, definitions, and Tables have been rearranged and considerably revised to improve clarity. Please see new Tables 1-1 through 1-5.
Segment:	1, 3
Organization:	Tri-State G & T Association Inc.
Member:	Keith V. Carman, Janelle Marriott
Comment:	Clarification is needed to address the potentially onerous implementation, administration, audit of the proposed revisions.
Response:	Thank you for your comment.
Segment:	5
Organization:	Tenaska, Inc.
Member:	Scott M. Helyer
Comment:	This standard has become too prescriptive and does too much to say "how" instead of "what" to do. Some of the information in the various tables may or may not conflict with manufacturer recommended practices. It is not clear at all whether such detail will lead to an increased level of reliability versus simply having consistency for the sake of consistency.
Response:	Thank you for your comment. The SDT has prescribed “what,” not “how,” except for those rare cases where it is necessary to specify both. Also, FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	6
Organization:	Florida Power & Light Co.
Member:	Silvia P Mitchell
Comment:	This standard is too prescriptive and will result in many violations.
Response:	Thank you for your comment. FERC Order 693 and the approved SAR assigned the SDT to develop a Standard with maximum allowable intervals and minimum maintenance activities.
Segment:	9
Organization:	Oregon Public Utility Commission
Member:	Jerome Murray

Comment:	The requirements in the latest draft are confusing and at times seem to be in conflict with other requirements. From a compliance and enforcement perspective, this confusion would make the standard difficult to audit.
Response:	Thank you for your comment. The Requirements, definitions, and Tables have been rearranged and considerably revised to improve clarity. Please see new Table 1-5.
Segment:	1, 6
Organization:	SCE&G
Member:	Henry Delk, Jr., Matt H Bullard
Comment:	While SCE&G believes the majority of the PRC-005-2 standard is ready to be affirmed there are still inconsistencies with areas of the standard that need to be corrected prior to approval. These inconsistencies are addressed in SCE&G's comments which have been submitted for the current draft of this standard.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1, 3, 5, 6
Organization:	Xcel Energy, Inc.
Member:	Gregory L Pieper, Michael Ibold, Liam Noailles, David F. Lemmons
Comment:	Xcel Energy believes the standard still contains many aspects that are not clearly understood by entities, including what is needed to demonstrate a compliant PSMP. Comments have been submitted concurrently to NERC via the draft comment response form.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	8
Organization:	Utility Services LLC
Member:	Brian Evans-Mongeon
Comment:	See filed comments
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1
Organization:	Baltimore Gas & Electric Company

Member:	John J. Moraski
Comment:	Please refer to BGE comments submitted for Project 2007-17 / PRC-005-2 Draft 2, submitted on 7/16/2010.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1, 3, 5, 6
Organization:	Public Service Electric and Gas Co., PSEG Energy Resources & Trade LLC
Member:	Kenneth D. Brown, Jeffrey Mueller, David Murray, James D. Hebson
Comment:	Please reference comments submitted by the PSEG companies on the official comment form for this standard.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1, 3, 3, 3, 3, 5
Organization:	Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power, Southern Company Generation
Member:	Horace Stephen Williamson, Richard J. Mandes, Anthony L Wilson, Gwen S Frazier, Don Horsley, William D Shultz
Comment:	Comments for this ballot are included in the Southern Company submitted comment form - Project 2007-17: Protection System Maintenance and Testing.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1
Organization:	Duke Energy Carolina
Member:	Douglas E. Hils
Comment:	Please see our responses in the comment form - thank you.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	1
Organization:	GDS Associates, Inc.
Member:	Claudiu Cadar
Comment:	All comments included in the NERC comment form

Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	3
Organization:	Louisville Gas and Electric Co.
Member:	Charles A. Freibert
Comment:	Comments will be submitte4d under the comment form
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	4, 5
Organization:	Ohio Edison Company, FirstEnergy Solutions
Member:	Douglas Hohlbaugh, Kenneth Dresner
Comment:	Please see FE comments for suggested enhancements submitted via the parallel comment period for this standard
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	5
Organization:	PPL Generation LLC
Member:	Mark A. Heimbach
Comment:	Please see comments submitted by "PPL Supply" on 7/16/10.
Response:	Thank you for your comment. Please see the SDT response in the Consideration of Comments.
Segment:	4
Organization:	Detroit Edison Company
Member:	Daniel Herring
Comment:	1. The definition should clarify whether current and voltage transformers themselves are included. 2. This implementation plan and the one for PRC-005-2 should be consistent.
Response:	Thank you for your comment. 1. These devices are included in the modified definition. This component of the Protection System definition is to generally include this functionality as a part of the Protection System. The detailed applicability of this component within PRC-005-2 is addressed within the Standard.

	2. This comment appears to be addressing the Implementation Plan for the Definition, not for the Standard.
Segment:	9
Organization:	California Energy Commission
Member:	William Mitchell Chamberlain
Comment:	The current proposal does not require coordination within the interconnection. 1. The standard should require the PCs within an interconnection to coordinate a UFLS Design with all other PCs within the interconnection and that the PCs should be required to develop a coordinated interconnection wide UFLS Design. As proposed the standard could conceivably result in as many different UFLS plans within WECC as there are Planning Coordinators. Additionally, the proposed standard fails to address UFLS relays which are currently part of the existing program which are owned by the customer. Recognition of customer owned relays is critical to have a successful program. To assure areas are covered the LSE needs to be included in the Applicability section. A third concern is the proposed standard attempts to establish continent wide frequency-time curves and eliminate discrete set points. This approach fails to recognize the unique characteristics of the four individual interconnections. Frequency-time curves do not allow for specific and defined measurements and will leave individual entities defaulting to the lowest common denominator. If frequency-time curves are intended to define the boundaries, the determination of discrete set points would fall into the hands of the PCs leading to disagreements among entities. In addition, to determine the frequency-time curves through stability and dynamic modeling, one must establish discrete set points. Frequency-time curves are reverse engineering and require justification and correlation to the reliability of the interconnections – no such justification has been provided.
Response:	Thank you for your comment. Your comments appear to be directed to the NERC Standard addressing development of UFLS programs. The Protection System Maintenance and Testing SDT is unable to address these comments.