Individual or group. (47 Responses)
Name (33 Responses)
Organization (33 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (38 Responses)
Question 1 Comments (44 Responses)
Question 2 (34 Responses)
Question 2 Comments (44 Responses)
Question 3 (34 Responses)
Question 3 Comments (44 Responses)
Question 4 (34 Responses)
Question 4 Comments (44 Responses)
Question 5 (0 Responses)
Question 5 Comments (44 Responses)
Question 6 (0 Responses)
Question 6 Comments (44 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The deleted R6 should have been shown in the PRC-005-X posted redline.
No
The wording in the note added to the title box of Table 5 is confusing. It refers to Table 1-5, yet in the title box for Table 1-5 it states that Sudden Pressure Relaying is excluded.
Yes
This is assuming that the data retention section referred to in the question and the standard's 1.2 Evidence Retention are one in the same.
Yes
Regarding the sync-check relays mentioned in 2.4.1 Frequently Asked Questions:, because their operation is reliant upon voltage inputs, sync-check relay maintenance must be addressed in the tables, specifically maintenance done with voltages applied. Table 4-2(b) addresses control circuit paths, but verifying a control circuit path could be done by manually blocking contacts closed.
The title box for Table 1-5 refers to "...Automatic Reclosing (see Table 4)..." There is no Table 4. It should be reworded to read "Tables 4-1 through 4-2" as it reads in the title box for Table 2. The many tables and cross references between the tables in the standard make the standard difficult to use. Reorganizing the tables, possibly having one table per component type with component attributes listed should be considered.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
Yes

Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Group
MRO NSRF
Joe DePoorter
Yes
The NSRF in the last posting had pointed out some issues related to the R6 requirement. With removal of the requirement in this posting those issue have been resolved. Thank you.
No
It is not clear in Table 5 if verification of the pressure or flow sensing mechanism is operable includes a test that the fault pressure relay when activated actually operates the auxiliary relay, elctromechanical lokout device or circuit breaker or other interrupting device to which it is conntected? Is it intended that this test is a part of the control circuity test of Table 5? It is recommended that a clarification be made for this issue either in Table 5 or the reference document.
No
Requirement R5 related to unresolved maintenance issues only applies when such an event occurs and that may not be associated with a particular periodic maintenance activity. It would seem more appropriate to retain records on the instances of unresolved maintenance issues that occuured since the last audit.
No
With the modifications to R3, it is implied that a newly idenfified automatic reclosing component would have the maximum maintenance interval as a deadline from when it is newly identified for its initial maintenance under the standard. This seems to be what the rationale for R3 indicates. It is suggested that be more clearly stated.
: The NSRF does not agree with the proposed wording in the Evidence Retention section, which states “In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of, all performances of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained”. The Maximum Maintenance Interval prescribed in all Tables is the enforceable component of when each entity must complete their Maintenance Activities. Any entity may elect to perform any Maintenance Activity at anytime for any reason. The NSRF recommends that the most current documentation of the associated Maintenance Activity be maintained. The NSRF believes that maintaining ALL maintenance documentation, regardless of what the Standard states is outside the scope of the Standard and does not add to increased reliability but rather an increased risk of not maintaining ALL past maintenance documentation. If the SDT wants ALL maintenance records since the last audit, then state that and prescribed table of “intervals” will not be necessary.
Group

Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes
Yes
Yes
None
Sudden pressure relays, which do trip some transformers, are not important in preventing “instability, cascading, or separation.” CSU believes that the inclusion of sudden pressure relays in the NERC Standards will not improve the reliability of the BES, and are outside the FPA Section 215 jurisdiction. The following are some additional notes on this topic. We also support FMPA's proposed language. • Many transformers are not protected using sudden pressure relays. In fact, due to the sensitivity of sudden pressure relays to vibration, some areas of the country purposefully do not use sudden pressure relays for transformer protection. • Many transformers that are protected using sudden pressure relays use a guarded trip scheme. For example, in order for the sudden pressure relay to trip the transformer there must also be another condition present such as an over current or differential trip. • There is not a consistent application of sudden pressure relays in the industry, many transformers do not utilize these relays for protection, and no requirements exist to have sudden pressure relays. CSU believes that including them in a standard will discourage their use and/or encourage those that currently use them to remove them from their protection scheme. Sudden pressure relays when applied correctly can be an asset in transformer protection, but are not important in preventing “instability, cascading, or separation.”
Individual
Mark Wilson
Independent Electricity System Operator
Yes
Yes
Yes
Yes
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
Yes

Table 5 – The interval for fault pressure operability is 6 calendar years, though some relays will require equipment outages to safely perform this work. AEP suggests aligining this maintenance interval with that of the associated equipment (transformers, reactors, etc.), which would typically be between 10 and 12 years within the industry. Taking this equipment out of service to perform fault pressure related maintenance would be a detriment to reliability.
Table 5 – The interval for fault pressure operability is 6 calendar years, though some relays will require equipment outages to safely perform this work. AEP suggests aligining this maintenance interval with that of the associated equipment (transformers, reactors, etc.), which would typically be between 10 and 12 years within the industry. Taking this equipment out of service to perform fault pressure related maintenance would be a detriment to reliability.
Individual
phan.si_truc@hydro.qc.ca
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Yes
Hydro-Quebec TransEnergie comments from first draft has not been considered.
Individual
Andrew Pusztai
American Transmission Comany, LLC
Yes
No Comment.
No
ATC recommends that the fault pressure relay be placed on a 12 calendar year maintenance interval. The best method to test the fault pressure relay is as a system with the seal-in relay and the control circuit. The auxiliary relay and control circuit are on a 12 year cycle. The Supplementary Reference and FAQ document states that the 6 year interval was based on similar Protection System components, but there are not other Protection System components that are similar to fault pressure relaying. Smaller populations of fault pressure relays would make it more difficult to utilize performance-based invervals except for the largest utilities.
Yes
No comment.
Yes
No comment.
No comment.
No comment.
Individual
Dan Bamber
ATCO Electric
No
Transmissions owners should be informed of the generator data for determining BES generating sites.
Yes
Yes

Yes
No comments
Pressure Relief Device (PRD) works on absolute pressure threshold. Currently these is no methodology to verify PRD sensing mechanism operation simulating required pressure. Can the drafting team an answer in the FAQ to guide us. Should PRD's not belong to the sudden pressure relay category?
Individual
John Falsey
Invenergy LLC
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP ("ICLP") agrees that a requirement specific to Balancing Authorities (or Reserve Sharing Groups) does not need to appear in the standard, but there must be an alternative binding means to provide the same information. Otherwise it is not clear to us how we would know the size of the largest generating unit in the BA/RSG footprint – or if it has changed. For example, if the RSG member with the largest generating unit suddenly decided to leave the Reserve Sharing Group, the applicability criteria would change without notice. Similarly, it seems unlikely that the BA/RSG would provide sufficient advance notification that the largest unit in their footprint is being decommissioned; reasoning that this is somewhat confidential information. As it stands now, the possibility exists that every affected Generator Owner and Transmission Owner would be found in violation of PRC-005-X based upon an action outside of their control or knowledge. This is inconsistent with reasonable principles of reliability compliance as we understand them.
Yes
ICLP fully agrees with the changes made to Table 5. By taking these actions, the project team has established consistency with the other control circuitry activities and intervals – which we have found reduces ambiguity in our compliance process and internal controls.
Yes
ICLP believes that the project team has fully captured FERC's intent in their recently issued NOPR to approve PRC-005-3. We agree that there is no reliability purpose served in maintaining Protection System test records that may be a decade or older just to confirm compliance with long interval activities. There should be plenty of other evidence that a relay owner has sufficiently strong internal controls necessary for an adequate BES Protection System Maintenance Program.
No
Similar to our response to Question 1, ICLP needs assurance that a sufficient grace period is provided to the recloser owner when the applicability criteria changes in the BA/RSG footprint. The integration of previously non-applicable reclosers into our PSMP could take years until an opportunity to perform relay and control circuitry testing presents itself. We were satisfied with the three years previously allowed under R3 and R4 – and those time frames should be captured somewhere in a binding manner. As it stands now, Draft 2 of PRC-005-X seems to stipulate that the change in applicability would take effect immediately, an unrealistic proposition in our view.
Individual
Joe O'Brien on behalf of Alan Neff
NIPSCO
No

All Sudden Pressure Relays do not affect the reliable operation of the BES. Some Sudden Pressure Relays are installed for equipment monitoring and other functions. We are suggesting that the language include mandatory maintenance and testing for only those relays that are used to support the reliable operation of the BES. It should be noted that this testing requires a vacuum setup and/or removal of the relay from the transformer. The relay will add many hours to the time required to test each transformer protection package.
Individual
David Thorne
Pepco Holdings Inc
Yes
Yes
Yes
Yes
no
no
Individual
Oliver Burke
Entergy Services, Inc.
Individual
Robert W. Kenyon
NERC
Yes
Yes
Yes
Yes
Comments on PRC-005-X September 11, 2014 I should mention that the following comments are presented from the point of view of enforcing the standard, not from the point of view of a Protection Engineer. Moreover, the comments are guided by the philosophy that we enforce the explicit Requirements put forth within the Standard. To be an enforceable matter, an explicit statement clearly stating the explicit obligations should be provided within the Standard. Requirement 1 Requirement 1 does not present a complete and unambiguous statement as to the obligations imposed on the Registered Entity. There is no clear statement as to what has to be documented in the Registered Entity PSMP. There are two parts provided, but these are in fact the only specific elements mentioned. The intent of these Parts is unclear. As written, they simply require the entity to identify whether the entity uses BPM, TBM, or a combination in each COMPONENT TYPE. COMPONENT TYPE simply alludes to whether relays, batteries, etc. are being addressed. Thus if an entity uses only TBM for relays, it can so state. No data on individual components is required. There will be 9 component types when PRC-005-X is in force. To comply, all an entity will need to do is to list the nine types and next to each identify which approach (TBM, BPM, and Combination) is used within that component TYPE. The value of this information is hard to identify. Part 1.2 obligates the entity to identify attributes used to extend maintenance intervals, if such use is made. Complying with that, as written, merely obligates the entity to list the 9

component types and any attributes which any components with each COMPONENT TYPE may be using to extend the interval. Again, no information on any individual Component is required. Again, the purpose of obligating the entity to create such a list is unclear. It must be emphasized that as written, these Parts focus on the COMPONENT TYPE - NOT the Components. A careful reading of these parts reveals that they only obligate to list some information relating to the COMPONENT TYPE level - the value of which is hard to discern. Unfortunately, these two Parts (1.1 1nd 1.2) are the only specific obligations imposed on the entity by the Standard. To be of any use, a PSMP would require vastly more information, particularly considering the amount of very detailed maintenance tasks required by PRC-005-X. Yet by including only Parts 1.1 and 1.2, it is implied that only the lists provided above are required in the PSMP. Entities could justifiably believe they were in compliance by simply creating the two lists alluded to above. Note that PRC-005-1 EXPLICTLY obligates the entity to include in its program identification of maintenance intervals and procedures. The situation will be basically the same under PRC-005-X. Although NERC has now imposed maximum intervals and minimum activities, the entity still must determine its own program. The NERC interval and activities requirements are limits within which the entity still must develop its own program, as it did under PRC-005-1. Why has this Standard dropped the obviously essential need to identify the factors such as interval and activities in the PSMP? If that were not the intent, why are some specific obligations (Part 1.1 and Part 1.2) identified and others not? Suggest that Requirement 1 be re-written, dropping the existing Part 1.1 and 1.2, because they appear to provide no useful information, being limited by their language to the COMPONENT TYPE level. Parts should be added identifying specific requirements in the PSMP document, such as intervals, maintenance activities, and other essential specifics for a useful and effective PSMP. All specific activities, policies, etc. needed to comprise an effective PSMP should be identified in a Requirement 1 Part. Requirement 2 There are numerous issues with Requirement 2. In general, some elements are presented in a confusing manner, at least one is erroneous, and the Requirement does not address situations which following Requirement 2 will eventually lead to. Requirement 2 identifies procedures that the entity must follow, first to establish PBM Segments, and then to annually maintain the justification for using each individual Segment. These rules are not stated in Requirement 2 itself. Instead, the entity is referred to Attachment A of PRC-005-X. Some steps in Attachment A are difficult to understand. Requirement 2, Attachment A, Establishing Justification, Step 2. Step 2 obligates the entity to: “Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.” But note that “Tables 1-1 through 1-5, ….” referenced above establish not only the “maximum allowable interval” but also “minimum maintenance activities”. Yet Step 2 above provides a clear requirement to follow the table “Intervals”, while making no mention of the table-prescribed “minimum activities”. Recommend that the Step be re-written establishing clearly whether Step 2 requires the use of both the “maximum intervals” (as specified) and the “minimum activities” (left uncertain). Requirement 2, Attachment A, Establishing Justification, Step 4 To establish a PBM Segment, the entity is directed to identify components for the Segment, maintain so many of these, and use the results to determine a revised maintenance interval. The determination is provided at Step 4 of the process in Attachment A alluding to “establishing” justification for PBM. But although the entity is directed to determine the upcoming year interval, no guidance on how to do this is provided. An earlier Reference Document strongly implied that the interval cannot be extended unless the previous Countable Events Rate does not exceed 4%. However, no such restrictions appears in the Requirement. Are entities forbidden to extend maintenance intervals if during the “establishment” phase they encounter a CE rate exceeding 4%? If so, this should be explicitly stated. Note that an entity most certainly could follow Attachment A when establishing a Segment, have a CE rate exceeding 4%, and still reasonably conclude that an extended interval was warranted. As an example, a CE rate exceeding 4% may have been realized but the entity has concluded that the rate was an anomaly, based upon a subsequently uncovered manufacturing issue with a very small batch of devices. The point is, what is the intent of Step 4 in the “establishing” section – is the entity precluded from selecting a longer interval if it experiences a CE rate exceeding 4%? One reference document strongly suggests so, but there is no such proscription in the Standard. In short, Step 4 should be clarified as to whether a 4% or less CE rate must be achieved before PBM intervals can be established. Requirement 2, Attachment A, Establishing Justification, Step 5 The intent of Step 5 in the “establishment” process seems to be to direct the entity to identify a maximum interval for the upcoming year, based on the previous year's performance, such that in the upcoming year, the segment will experience a CE rate not exceeding 4%. The actual wording is: Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year. This statement is very confusing and should be revised. One aspect contributing to the confusion is that the term "maximum allowable maintenance interval" apparently alludes, analogously, to the "Maximum Intervals" identified in the various Tables (Table 1-1, 1-2, etc.). But since the interval term is not defined and not in the glossary, and the term is not capitalized, the normal interpretation is that the entity must develop a generic "maximum" that will prevent a CE Rate exceeding 4% - which is not mathematically possible. The requirement should more clearly state that using the previous year's data, try to identify the longest interval which will most likely not result in a CE Rate exceeding 4%, in the upcoming year. Inconsistency Regarding Mandatory Countable Event Performance As an aside, the steps in Attachment A identify a PBM limit not exceeding 4%, while the corrective action requirement indicates that the CE rate must be LESS THAN 4%. While the difference is small, the difference (Less than 4% vs. not to exceed 4%) should be rationalized. Requirement 2, Attachment A, Maintaining Justification, Step 1 In the "maintaining justification" section, Step 1 obligates the entity to update the Component List. Presumably, this would include adding Components. Note that rather stringent requirements covering establishment of a PBM Segment are provided. Segments cannot be created without following the rules of Attachment A. But no guidance is provided addressing adding Components to an existing Segment. Suggest a clear statement in the Standard that during the updates, any component having the properties of the Segment can be added to the Segment. Presumably, the update will include dropping retired components form the Segment. No guidance is provided in the Standard addressing dropping Components at the will of the entity. Is this permitted? Moreover, there is no guidance as to what the entity must do when the Segment population drops below the mandatory 60 Components. A clear statement is made in the Standard that a Segment must be at least 60 Components. Maintaining a Segment of less than 60 components via PBM is clearly identified in the Standard as a violation. What are the rules when attrition or, perhaps, dropping Components voluntarily brings the Segment population below 60 Components? Presumably, the use of PBM on that Segment must be discontinued. But what rules apply? Perhaps, the entity must revert to TBM. But having using PBM, many if not all of the Components will not have been maintained under the TBM rules. Therefore, if the Segment is simply dropped back into the TBM rules, the entity could well be forced into maintaining every single Component in the Segment in one year, which, could exceed the maintenance capabilities of the entity. There is no guidance covering these instances, which over time, will occur with every PBM Segment established. Recommend guidance be provided. Presumably, if new components are added to the entity system, perhaps they can simply be added to the Segment population. However, no guidance is provided as to whether this is mandatory. Note that Step 1 of the "Maintain" process does explicitly obligate the Entity to "update" the Segment. Guidance should be provided as to whether the obligation stated in the standard to "update" the Segment includes mandatory additions of new components on the system with the attributes of the Segment. Again, recommend guidance be provided. Requirement 2, Attachment A, Maintaining Justification, Step 2 Step 2 in the "maintain justification" rules obligates the entity to: Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year. The intent of this Step is to establish a "floor" on maintenance performed. It should read: Perform maintenance on AT LEAST the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year. The Standard Provides no Means to Prevent the Entity from "Gaming the System" to Drastically Reducing Maintenance Activity Note that following the procedures provided in Attachment A, a given entity will probably have no devices to maintain in the year following the establishment of a Segment. This is because, presumably, the entity was following TBM intervals, and the purpose of PBM is to extend those intervals. As an example, an entity would have maintained all its unmonitored relays at a 6 year interval under TBM. After establishing a PBM Segment for these for the next year, the entity will be establishing a new interval which could well be 8 or 9 years. Since the entity had been maintaining these relays under the TBM six year interval, but a newly established Segment of 8 years is now in place under PBM, that will leave the entity with nothing to test in the following year, since everything was already maintained with the last 6 years. Under Step 2 above, the entity will still have to test at least 5% of the population. There is nothing preventing the entity from re-testing that 5% of the population which was tested most recently. This will probably result in a very low CE rate, probably zero, which will obligate the entity to again test under the 5% rule of Step 2 in the following year. Again, there is nothing preventing the entity to again re-test the same devices it's been now testing for two years in a row, and it appears this could continue for many years. Thus PBM as established in the Standard apparently can be manipulated or "gamed" in manner that all but stops maintenance but leaves the entity 100% compliant with the Standard. Provisions should be added which close this gap. Requirement 2, Attachment A, Maintaining Justification, Step 3 Under the "establish" section of Attachment A, the Standard explicitly obligates the entity analyze the results of its maintenance activity for the year, and to "develop maintenance intervals". Thus the entity is reasonably obligated to determine the interval for the next year based on an analysis of the past year's performance. However, in the corresponding section on "Maintaining" justification for PBM intervals, Step 3, the obligation on the entity to analyze "to develop intervals" is missing. Instead, the entity is merely obligated to: "For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment." Nowhere in the Section describing the "maintenance of PBM" is the entity obligated to use the results of the past year's maintenance to determine the interval for the next year. This obligation appears in the section of Attachment A as to "establishing" the Segment. But the obligation is not in the Section of Attachment A as to "Maintaining" the justification for PBM. In fact, there is no explicit obligation anywhere in Attachment A requiring the entity to take into account the performance of the previous year and thereby determine the Interval for the next year while maintaining the justification for Segment intervals in an upcoming year (unless the CE exceeds 4%). An earlier Reference document indicated that that is required. It appears the by oversight, the obligation on the entity to consider new Intervals each year based on the previous year's performance was dropped. Verbiage should be added making determination of the Interval for the following year be made by an analysis of the past year's performance. Presently, the only similar obligation on the entity while "maintaining" justification for ongoing use is the phrase "determine the overall performance of the Segment" in Step 3 of the "maintaining" section, which falls well short of an explicit obligation to thereby establish or a least consider now intervals. Recommend revising Step 3 such that a clear requirement be established that the entity evaluate its existing interval and determine whether adjustment is necessary, based on the prior year's performance. Requirement 2, Attachment A, Maintaining Justification, Step 4 Step 4 of the Attachment A section covering "maintaining" technical justification presents the same problems mentioned above regarding Step 5 of the rules for "establishing" justification for PBM Segments. The Table of Compliance Elements identifies failure by the entity to Reduce the CE Rate to 4% over three years as a violation, but the Standard does not establish this as a Requirement. The final line of Attachment A provides: "If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years." The above obligates the entity to do an action plan to reduce the CE rate to 4%. That's all. As written, this would permit the entity to go on forever with a CE rate exceeding 4% every year without penalty, as long as they had the plan, it was credible, documented, and executed. Yet the PRC-005-X "Table of Compliance Elements" identifies FAILURE to reduce the CE Rate as a Violation. Suggest the Standard be revised such that REDUCING the CE Rate to 4% or less is established as a Requirement. The Requirements in the Standard do not impose this obligation presently. The only such obligation in the Standard as written is to do the Action Plan, with no mention of success or failure. The standard is establishing a new obligation in the "Table of Compliance Elements" that is not supported by the Requirements in the Standard. The requirement, as written, does not obligate the entity to be successful; only to try. Suggest that bringing the CE Rate down to 4 % or less be established in the Standard as a clear Requirement. Drop Attachment A and place its Requirements in Requirement 2, with each Step established as a Part Requirement 2 is presented in an awkward manner. Requirement 2 provides nothing and simply refers the entity to Attachment A of the standard. There's no apparent reason for this. Attachment A provides requirements for establishing PBM Segments, maintaining them, and a third requirement for action plans. The requirements for establishing and maintaining the technical justifications are provided in numbered "Steps", with both processes using the same number sequence, so there are two Steps 1 and two Steps 2, etc. The Action plan material is not numbered. This makes referring to the various steps, etc. awkward. This problem could be fixed by dropping Attachment A, and numbering all its requirements as "Parts" of Requirement 2, providing clear identification of each element.

Recommend this be done. Requirement 3 Requirement 3 revolves around embedded tables that prescribe minimum maintenance activities and maximum intervals for Protection System components. The tables contain several sets of maintenance activities and minimum activities, for several different possible Component attribute configurations. However, the specific sets of intervals and activities are not numbered or otherwise identified. Thus, to refer to a specific set of intervals and activities, one is forced to use awkward language such as “the third row down in Table 1-1”. Recommend that these sets of intervals and activities each be provided a number or other identification system permitting efficient identification of each set. Requirement 3 and 4 Both Requirements 3 and 4 are very similar in that both obligate maintenance being performed. One uses TBM or extended TBM, while the other uses PBM. But the overall intent in both is the same: Do the maintenance. Note that under both Requirements, the Standard establishes MINIMUM maintenance activities which must be performed. However, these are MINIMUM Requirements, and the Entity may indeed and probably will add activities to its own program. So while the entity program will include the minimum activities specified in the Standard, the entity program will also include activities identified and desired by the entity. This is true for both Requirement 3 and Requirement 4, in both TBM and PBM. However, a close reading of these two Requirements reveals that they impose significantly different obligations. Requirement 3 requires: “Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through …” However. Requirement 4 requires: “Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s).” Note that R3 requires the entity to simply meet the minimum requirements in the Tables, while R4 requires the entity to “implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). In other words, R3 does not obligate the entity to do the maintenance activities it selected on its own, but R4 does, since in contrast it requires the entity to “implement and follow its PSMP”, which presumably would have to include the maintenance activities added to the PSMP by the entity. Recommend this disconnect be reviewed and rationalized. There is no apparent reason for there being different obligations under R3 and R4. Having different requirements could motivate entities to not add desirable additional testing to avoid jeopardy. It could also lead to confusion as to just what the Requirements are. Requirement 5 This requires: “Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues.” However, the Evidence Retention Section of the Standard makes no mention of the data required to evaluate entity compliance with this requirement and establishes no retention period. Obviously, data from prior years will be required to evaluate compliance. Evidence Retention Section The “Evidence Retention” section does not establish data retention periods for entity retention of information documenting its establishment of PBM Segments or the justification for the continuing use of PBM (Requirement 2). Maintaining the justification for the continuing use of all PBM Segments is an annual Requirement and is at the heart of the entire PBM process. Its importance is reflected in the VSL Level associated with failure to develop these justifications – SEVERE. Yet the “Evidence Retention” section of the Standard imposes no retention period for the rather extensive documentation required to ensure such justifications were performed. Recommend that the “Evidence Retention” section be revised to require the entity to retain all documents and evidence to support the establishment and maintenance of the justifications for PBM Segments. It is recognized that M2 states that the entity must have such evidence FOR ITS CURRENT PROGRAM. Recognizing that developing the technical justification for every Segment is an ANNUAL REQUIREMENT, and that TOs will probably be audited every 6 years, if the data retention is limited to the Current Program, then compliance with R2 can never be audited with respect to 5 out of every 6 PBM Segment programs developed. Evaluation of compliance for the five years will not be possible. Again, recommend that the “Evidence Retention” section be revised to require keeping all technical justification documentation prepared since the last audit. Data Base Issue As written, the standard does not require the entity to maintain data on its usually vast Protection System in any orderly manner. Note that large entities will have populations in the thousands of Components. It is recognized that there would probably be issues gaining universal acceptance of any one format, but

convenient access to data will be essential for Auditing purposes as well as management of the Protection System Function by the Entity. As an example, the audit team will need to evaluate compliance with maintenance intervals. But without knowing whether a component is maintained under PBM or TBM, whether monitoring has been applied, what the present and past variable PBM intervals have been (if applicable), and the specific table under which a Component is being maintained, evaluation of compliance with the complex rules will be impossible. This is but one example. Recommend that NERC consider developing a standard format for Protection System Components. Consideration should be given to developing an associated application which can periodically import maintenance records and conduct an evaluation of compliance. Such an application could also assist the entity in managing its maintenance.
Individual
John Seelke
Public Service Enterprise Group
PSEG supports the comments submitted by Florida Municipal Power Agency (FMPA) In addition, PSEG provides the following additional comments: PSEG, like many TOs and GOs, has Sudden Pressure Relays (SPRs) as a third level of transformer protection – primary and backup transformer differential relays would isolate the transformer in case of a fault. For some TOs or GOs, the SPR is a backup to its primary transformer differential relay. In this this case, SPRs should be tested under PRC-005-X. However, in the first case, no maintenance interval should be required by a NERC standard since primary and backup differential relays are both subject to PRC-005-X testing. (As practical matter, SPRs that are a third level of protection would be tested as good utility practice during the normal transformer maintenance, which has on its own maintenance interval that's unrelated to SPR maintenance.)
Group
Dominion
Mike Garton
No
If the BA is not required to provide this information, applicable entities under this standard will not have the information necessary to determine whether they have applicable Facilitie(s) under 4.2.6.1.
Yes
Yes
Yes
No.
Yes; Dominion commends the SDT for its articulate summary of changes.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
No
Errors in the text of Table 5 remain. It fails to differentiate the maintenance interval between monitored and un-monitored elements. The suggested change is: Change Component Attributes from "Control circuitry associated with Sudden Pressure Relaying" to "Unmonitored control circuitry

associated with Sudden Pressure Relaying from the fault pressure relay to the interrupting device trip coil(s)."
Yes
Yes
1. The revisions proposed effectively include all sudden pressure relays regardless of their reliability impact on the Bulk Electric System (BES). The Standards Development Team (SDT) is requested to develop criteria to reasonably identify and include only those sudden pressure relays that are essential and possibly disruptive in the BES, thus reducing the burden of the regulation and making it acceptable to the industry. 2. The Special Protection and Control Subcommittee (SPCS) provided good guidance but did not identify the maximum maintenance interval. Comments provided in the round of voting ending June 3, 2014 indicate that intervals of up to 12 years are routinely acceptable. This is also the maximum interval at Manitoba Hydro. This varies significantly from the informal survey by the SPCS with their conclusion of 6 years. The regulated maximum maintenance interval should consider typical industry maximums plus an allowance for minor variations to provide equipment availability. The SPCS should provide the maximum with consideration to the application, capability, loading, and reliability impact on the BES.
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
Yes
No comments.
Texas Reliability Entity, Inc. (Texas RE) supports this version of PRC-005-X and will vote affirmative in the ballot. We do, however, have suggested revisions for the definition of Countable Event. 1. Texas RE suggests that the first sentence of the definition, as written, appears to include each "condition" (i.e. issue) not each "'Component' with an issue" discovered during a maintenance cycles as e a Countable Event. Is it the intent of the SDT that if a relay had multiple issues discovered during a maintenance cycle that it would be considered as one countable event since countable events are defined at the Component level? It appears that the first sentence of the "Countable Event" definition allows multiple Countable Events for each maintenance of each Component. That could mean the maintenance of a single relay with multiple issues could push a Registered Entity's Countable Events to well over 4%. This potential appears to exist because the first sentence's second defined item says that a Countable Event is "any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, which requires corrective action". Texas RE suggests a revision to the first sentence of the definition for Countable Event, as follows (bracketed area represents new/changed text): A failure of a Component requiring repair or replacement, any [Component] condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-2, and Table 5, [to have one or more conditions which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure.] 2. Texas RE also suggests that the second sentence of the definition, as written, has unclear language that could result in different interpretations as to which Misoperations do not qualify as Countable Events. Texas RE suggests a revision to the second sentence of the definition for Countable Event, as follows (bracketed area represents new/changed text): Misoperations due to [any of the following are not included in Countable Events: product design errors, software errors, relay settings different from specified

settings, or errors with either configuration or application in Components of Protection Systems, Automatic Reclosing, or Sudden Pressure Relaying.]
Individual
Jonathan Meyer
Idaho Power Company
No
An Entity within a BA area could find itself out of compliance if they are not notified of the largest generating unit. Requiring an Entity to query the BA regularly seems unnecessary as the BA should always be aware of the largest unit and more easily in a position to notify its BA members.
Yes
Yes
No
Is it the intent of the DT to have a newly identified component only maintained prior to the maximum interval allowed for that component type in the Tables? This would be our interpretation if no additional clarifying language is added. A timing Requirement or additional language is needed if this is not the case.
No
No
Individual
David Jendras
Ameren
Yes
Ameren agrees with the SERC PCS response to this question and includes it by reference.
Yes
(1) We believe that stating the lockout relay and monitored control circuitry maintenance activities in Table 5 repeats what's in Table 1-5, and thus superfluous. (2) The note below the title of Table 5 implies to us that if such Components differ from those in Table 1-5, they are outside Applicability in both PRC-005-2 and PRC-005-3. Is that correct?
Yes
Yes
Ameren agrees with the SERC PCS response to this question and includes it by reference.
(1) Ameren agrees with the SERC PCS response to this question and includes it by reference. (2) We understand the use of 'pressure or flow sensing' within the first Table 5 Maintenance Activity is within the context of the PRC-005-X Fault pressure relay definition and therefore does not include other types of pressure or oil flow devices found on transformers. Correct?
Individual
Jamison Cawley
Nebraska Public Power District
Yes
No
We feel the current draft of Table 5 is too broad in the use of the term,"Any Fault Pressure Relay". The SCPS report conclusion (Page 31) indicates, "Where the device is installed to respond to rapid pressure rise in facilities described in the applicability section of Reliability Standard PRC-005, and configured to take action to initiate fault clearing to support reliable operation of the Bulk-Power System, it should be included as a device to be maintained and tested". Since many SPR devices are installed simply to protect equipment from excessive loss of life (or simply indication) rather than to

provide fault detection or clearing for the BES, the mandatory inclusion of Any Fault Pressure Relay to the PSMP via Table 5 falls outside the intended scope of the SPCS report. Additional validation of this interpretation is gained from the previous sentence in the SPCS document: “Where this device is applied to respond to abnormal equipment conditions, it takes action to protect the equipment from excessive loss of life or to indicate unavailability of service, rather than for the purpose of initiating fault clearing or mitigating an abnormal system condition to support reliable operation of the Bulk-Power System”. We feel if the device is not providing support for reliable operation of the Bulk Power System it should be excluded from the PSMP.
Yes
Yes
Individual
Than Aung
Los Angeles Department of Water and Power
Yes
No
LADWP does not support the addition sudden pressure relay to the PRC-005 standard due to the non-electrical fault nature of these devices.
Yes
Yes
Individual
Keith Morisette
Tacoma Power
Yes
While Tacoma Power does not support making PRC-005-X applicable to Balancing Authorities, removal of Requirement R6 does create additional burden for Transmission Owners, Generator Owners, and Distribution Providers to keep current on which Automatic Reclosing is applicable to PRC-005-X.
No
Tacoma Power does not support modification of the standard to include Sudden Pressure Relaying and therefore opposes inclusion of Table 5 in its entirety.
No
While Tacoma Power does support the proposed modifications to the data retention section for Requirements R2, R3, R4, and R5, the first paragraph of the section undermines the proposed modifications by granting the CEA authority to “ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit,” which could include retaining evidence from the previous audit period.
No
In the PRC-005-X Implementation Plan, Tacoma Power was not able to identify where cases were addressed in which Automatic Reclosing became applicable to the standard based upon changes to the largest relevant BES generating unit. Whether it is included in the Implementation Plan or the body of the standard, it is vital that Transmission Owners, Generator Owners, and Distribution Providers be afforded a reasonable timeframe to conduct and document the first testing under Tables 4-1 and 4-2(a), not only during initial implementation, but also in response to changes in

applicability. These entities may not receive much advance notice of changes in applicability, and it is unreasonable to require that they be compliant before the change in applicability takes place when the change in applicability is being triggered by another entity that is not required to provide notice to all impacted entities. (The wording in Footnote 2 reinforces this concern.)
No.
Yes. Recognizing that even the technical report acknowledges that "[t]here is no operating experience in which misoperation of a pressure switch in response to a system disturbance has contributed to a cascading event," it is a concern that an enforceable regulatory requirement to maintain sudden pressure relays will be established based upon a theoretical risk of inadvertent operation during a disturbance that might contribute to a cascading event. Consequently, unless evidence can be produced of actual inadvertent operation of sudden pressure relays protecting BES elements during a disturbance that, under slightly different system conditions, could have led to a cascading event (i.e., a "near miss"), modification of PRC-005 to address sudden pressure relaying should not be necessary at this time. Furthermore, as mentioned on page 4 of the Summary of Comments, "FERC stated that any component that detects any quantity needed to take an action, or that initiates any control action (initial tripping, reclosing, lockout, etc.) affecting the reliability of the Bulk-Power System should be included as a component of a Protection System. Accordingly, to address FERC's concern, pursuant to section 215 (d)(5) of the FPA, FERC proposed to direct NERC to develop a modification to the Reliability Standard to include any component or device that is designed to detect defective lines or apparatuses or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit actions." This argument in favor of including sudden pressure relaying could easily be extrapolated in the future to include other equipment protective functions such as (but not limited to) IEEE 26, 49, and 71 functions. There is concern that the SPCS report's recommendation not to include these functions could be disregarded in the future after the industry has acclimated to regulated testing of sudden pressure relaying.
Individual
Israel Beasley
Georgia Transmission Corporation
Yes
Yes
Yes
No
We could only agree if the issue were addressed in the implementation plan. The removal of a direct statement regarding newly identified Automatic Reclosing Components from both the standard and the implementation plan (see Rationale for R3 and Rationale for R4) leaves the initial maintenance required date ambiguous. We suggest the following addition to the implementation plan: "Newly identified Automatic Reclosing Components shall be treated as being commissioned on the date of discovered applicability for the purposes PRC-005-X. The first maintenance records for newly identified Automatic Reclosing Components shall be dated no later than the maximum maintenance interval after the identification date. The maximum maintenance intervals for each newly identified Component are defined in Tables 1-1 through 1-5, Table 2, and Table 4. No activities or records are required prior to the date of identification."
The change listed in response to question 4 probably should also be added to the FAQ.
Individual
Bill Fowler
City of Tallahassee

The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Individual
Gul Khan
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Group
Florida Municipal Power Agency
Carol Chinn
Yes
No
See comments for Question 6
Yes
Yes
1) In Order No. 758, the Commission accepted NERC’s proposal to the NOPR to develop technical documents (SPCS report) to determine those protective relays that are necessary for the reliable operation of the Bulk-Power System and allow for differentiation between protective relays that detect faults from other devices that monitor the health of the individual equipment and are advisory in nature (e.g., oil temperature). Currently as drafted this standard, PRC 005-X, may apply to Sudden Pressure Relays installed for equipment monitoring and protection. This is due to the fact that, as currently drafted, the Applicability section for Facilities (4.2.1) is too broad due to the inclusion of the term “Fault” and how that term is defined in the NERC Glossary: “4.2.1 Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)” NERC Glossary definition of Fault: “An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.” If the glossary term only referenced “short circuit”, then this would not be a problem. But the fact that broken wires and intermittent connections are part of the definition for Fault, this greatly broadens the term Fault to include potential events that would have little to no reliability impact to the BES,

such as turn to turn faults in wound electrical apparatus. Consequently, the use of the term Fault as proposed in the Applicability section of this draft standard PRC-005-X unnecessarily broadens the Applicability of the standard to include devices which do not have a BES reliability related purpose. Suggested language that can be incorporated to help meet the FERC directive and address the reliability concerns is as follows: “Sudden Pressure Relays that are installed as the primary or back-up relay for the purpose of detecting phase-to-ground or phase-to-phase short circuit on the BES.” Clarifying the Applicability with this phrase focuses the standard applicability to testing of devices that are relied upon to clear short circuits of sufficient magnitude to have a reliability impact. That is, the proposed language results in testing that is focused on devices for which there is a reliability-related need to confirm the positive operation of the device. 2). Additionally, Fault is not used in 4.2.5, and as such GSU transformer applicability is even more encompassing. Again, suggest modifying 4.2.5 to say “Sudden Pressure Relaying installed for the purpose of detecting phase-phase and phase-ground short circuit on the BES and Protection Systems for generator facilities that are part of the BES, including: …” 3.) The proposed definition of Sudden Pressure Relaying is inconsistent with the SPCS report analysis of the 63 device function number in Appendix D (page 31 of SPCS report). The 63 device function number discussion, in its entirety, focuses on gas and oil PRESSURE relays. Furthermore, although not stated, the discussion and description of performance history and issues with these relays is specific to transformer tank mounted gas and oil pressure relays. The proposed definition of Sudden Pressure Relaying adds the term “oil flow” to the definition of a “Fault Pressure Relay”, a term not mentioned or addressed by the SPCS report. This definitively includes Bucholz relays in the definition of Sudden Pressure Relaying and, hence, the new applicability. Although Bucholz relays typically respond to both pressure and oil flow, the pressure detection method is quite different from tank mounted pressure relays. Industry literature and operating history, including reports on fault pressure relaying that pre-date the SPCS report (and which were relied upon by the SPCS), indicate there is little risk of Bucholz relay misoperation due to external faults and no such known misoperations. By extrapolating the language of the SPCS report, the SDT has expressly included devices that were not discussed or postulated by the SPCS, and which have little to no risk of misoperation for external faults. If the only differentiator and justification for including sudden pressure relays in the PRC-005 standard/applicability is the risk of operation for external faults, then Bucholz relays should be explicitly excluded. Due to the dual operating functions of the relay, FMPA believes the only straightforward solution is to directly exclude these devices. Simply removing the phrase “oil flow” does not fully resolve the issue. FMPA requests this comment be considered on its own merits, but given extra emphasis should FMPA’s suggestion regarding the purpose of the installed sudden pressure relaying not be addressed by the SDT.
Individual
Christy Koncz
Public Service Enterprise Group
These comments replace previous comments submitted on 9/11/14 by John Seelke of Public Service Enterprise Group. PSEG supports the comments submitted by Florida Municipal Power Agency (FMPA) In addition, PSEG provides the following additional comments: PSEG, like many TOs and GOs, has Sudden Pressure Relays (SPRs) as a third level of transformer protection – primary and backup transformer differential relays would isolate the transformer in case of a fault. For some TOs or GOs, the SPR is a backup to its primary transformer differential relay. In this this case, SPRs should be tested under PRC-005-X. However, in the first case, no maintenance interval should be required by a NERC standard since primary and backup differential relays are both subject to PRC-005-X testing. (As practical matter, SPRs that are a third level of protection would be tested as good utility practice during the normal transformer maintenance, which has on its own maintenance interval that’s unrelated to SPR maintenance.) Furthermore, any internal transformer fault, including turn-to-turn short circuits, whether detected by the SPR or the differential relay, will generally put the transformer out of service and beyond repair. The use of the SPR MIGHT help avoid some

environmental impact, but does not add to the reliability of the BES in any way and will not save the transformer. Finally, when used in conjunction with redundant differential schemes, the application of the SPR for tripping purposes is not required as noted above. This being the case, if the standard passes “as is,” TOs and GOs that do not currently perform testing at the prescribed intervals in the standard will meet compliance requirements by either 1) Decreasing the transformer maintenance interval or by 2) Rewiring the SPR as an alarm function. For PSEG, decreasing the maintenance interval will require removing the BES transformers from service approximately twice as often as they are now. That presents a reliability concern. Removing the SPR from the tripping state to the alarm state does not present a NERC BES reliability concern, and as such we will be forced to consider this option.
Individual
Scott Langston
City of Tallahassee
Yes
The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Group
DTE Electric Co.
Kathleen Black
Yes
Yes
Yes
Yes
No
No
Group
JEA
Tom McElhinney
Yes

Yes
The standard needs to be limited to items that take action to initiate fault clearing and should not include items that are simply meant to protect equipment.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
No
Disagree with the handling of sudden pressure relays. The added requirement for electical testing of the lockout relay should be deleted. Typically the physical seperation of the pathway by the lockout relay will prevent any signal flow. The key to this relay is if it will mechanically operate. Further, the lockout function only serves to prevent reclosing without a physical reset. For generator step up transformers this reclosing will occur when the unit is disconnected from the BES. There is no BES protection reason for testing this component.
Individual
Angela P Gaines
Portland General Electric Company
PGE still has concerns regarding the testing of the sensing mechanism of sudden pressure relays. Although some sudden pressure relays and newer Buchholz relays may be possible to test without draining oil or physically removing the Buchholz relay off the transformer, it does require taking the transformer out of service thereby reducing reliability of the BES. In cases where a Buchholz relay is required to be removed for testing, the added complexity would increase down time of critical transformers and introduce possibility that the relays are not reinstalled properly. Additionally newer microprocessor relays can provide sensitive sensing of internal transformer faults and these relays are routinely tested.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Illinois Municipal Electric Agency believes the comments submitted by Florida Municipal Power Agency warrant specific attention by the SDT, and a PRC-005 WebEx to specifically address the appropriate scope/applicability for PRC-005. It is unfortunate this was not done before the current ballot.
Group

ACES Standards Collaborators
Jason Marshall
Yes
Yes. The previous proposed R6 requirement was clearly a Paragraph 81 requirement that was purely administrative in nature and provided little to no support for reliability. Thank you for removing it.
No
We agree with most of the changes to Table 5; however, we believe additional explanation is required in the last row regarding the "(See Table 2)" reference. What part of Table 2? Is something in Table 2 supposed to explain this last row further?
No
The data retention continues to be problematic in that it requires data to be retained longer than is required by the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C – Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that many of the maximum maintenance intervals exceed audit periods (six years) for responsible entities, a responsible entity would be required to retain data previous to its last audit, which is not consistent with the Rules of Procedure. We suggest changing the data retention section such that the data only needs to be maintained since the last audit.
Yes
We agree with the deletions of the parts and sub-parts from the requirements. However, we do believe that is necessary to document in the implementation plan, a period of time for a responsible entity to become compliant should the standard become applicable to a new Automatic Reclosing Component particularly due to a change in the size of the largest unit in a Balancing Authority Area or Reserve Sharing Group. The implementation plan could be modeled after the "Implementation Plan for Newly Identified Critical Cyber Assets and Newly Registered Entities" developed by the CIP standard drafting team.
We have no new comments on the Supplementary Reference and FAQ.
(1) Applicability section 4.2.4 should be modified for clarity and to avoid potential conflicts with the definition of Remedial Action Schemes (RAS). The prior posting of the Remedial Action Scheme definition in Project 2010-05.2 – Special Protection Systems included the following statement: "these schemes are not Protection Systems." This statement would conflict directly with section 4.4.2 that states "Protection Systems installed as a Remedial Action Scheme." Even though current posting of the RAS definition has eliminated the clause causing the ambiguity, we suggest changing section 4.2.4 to simply be "Remedial Action Schemes" would avoid this ambiguity altogether and make PRC-005-X not dependent on changes that the other drafting team is making. (2) Thank you for the opportunity to comment.
Group
Duke Energy
Michael Lowman
Yes
No
Duke Energy questions the necessity of creating separate Tables for Sudden Pressure Relays and Automatic Reclosing Relays. We recommend the drafting team consider integrating the language found in the individual Tables in an effort to reduce the burden on the industry of monitoring and maintaining compliance with a number of different Tables.
Yes
Yes
Individual

Bill Temple
Northeast Utilities
Yes
Yes
Yes
Yes
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
The redline to last posting does not show R6 being deleted; is the correct redline posted?
Yes
Yes
Yes
Please state in the R3 Rationale the fact that all Automatic Reclosing, and Sudden Pressure Relaying Components are newly identified within PRC-005 applicability upon the effective dates of PRC-005-3 and PRC-005-X, respectively. Automatic Reclosing, and Sudden Pressure Relaying Components are not being transitioned from PRC-005-1 et al.
none
1) Please state in the Implementation Plan the fact that all Automatic Reclosing, and Sudden Pressure Relaying Components are newly identified within PRC-005 applicability upon the effective dates of PRC-005-3 and PRC-005-X, respectively. Automatic Reclosing, and Sudden Pressure Relaying Components are not being transitioned from PRC-005-1 et al. 2) Given a change in the largest unit in a Balancing Authority Area or RSG and additional reclosing relays become applicable to the standard, by when do the additional reclosing relays need to be maintained, by the date of the change in the largest unit, or by the end of the maximal interval period for the subject component? Suggest clarity be added to the footnote 2 associated to 4.2.6.1 or adding a clarifying statements to “How do you determine the initial due dates for maintenance?” Section 8.2.1 of the FAQ document. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Karen Webb
City of Tallahassee
Yes

The City of Tallahassee (TAL) believes Sudden Pressure Relaying should not be added to PRC-005-X because they are not necessary for the “reliable operation” of the bulk power system as defined in statute. What is necessary for the reliable operation of the BPS are differential relays, overcurrent relays, etc., that are there to clear a major phase to ground or phase to phase fault that if left uncleared can cause instability. The purpose for a sudden pressure relay is primarily to monitor equipment health, e.g., detecting a turn-to-turn failure, not a phase to ground or phase to phase fault. If a sudden pressure relay fails to operate, there is no threat to BPS reliability since the differential relay / overcurrent relays are there if the fault develops into a major phase to ground or phase to phase fault. TAL believes that the use of sudden pressure relays are a good business practice, but we also believe that utilities should be free to adopt good business practice beyond the requirements of the standards, without the reverse incentives that being regulated, audited, etc., bring.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM supports the removal of R6 and will be submitting an affirmative ballot.
PJM urges the SDT to review and address PSEG’s concern regarding inclusion of a required maintenance interval for Sudden Pressure Relays (SPRs) that are utilized as a third level of transformer protection and are not a primary or backup transformer differential relay.
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
Yes
Yes
Yes
no.
yes. During the webinar, when asked for clarification regarding changes in the largest unit as found in Footnote 2, the SDT Chair indicated that newly identified Automatic Reclosing Components would fall into the maintenance cycle as found in the applicable table for that specific component. While we concur with that interpretation, we have concerns that Footnote 2 gives the impression that those components would be subject to the standard on the date the change occurred and those components would have to be compliant on the date of the change. We suggest the SDT make the following addition to Footnote 2: The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change. From that day forward, those components would then have to be maintained according to the maintenance cycle as found in the applicable table for that specific component.
Group
Bonneville Power Administration
Andrea Jessup
Yes

Yes
Yes
Yes
No.
Yes. BPA requests clarification on the following definition and the intent of the definition. BPA understands the definition was created before the inclusion of sudden pressure relays (which includes buchholz and sudden flow relays as well). Attachment A (PBM) the definition of Segment: "Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a segment. A segment must contain at least sixty (60) individual components." It appears that the intent is to monitor the segment of 60 for consistent performance to determine if it is acceptable to combine population segments. If this type of tracking is the intent and populations are tracked by manufacturer and model, is it also the intent to create components of a common application that typically share common elements, such as a mechanical buchholz device regardless of manufacturer? If there is a significant performance difference among manufacturers of a buchholz device it would be evident during the tracking process when the events are counted and the populations compared. If various application stresses and fatigue become the driving force for an item to fail, it is likely to be manufacturer independent and grouping by buchholz relay would be the best way to track performance. BPA's concern is that if the definition is tied to the manufacturer and model, many items that may have benefited from a performance based maintenance program will not be included due to the difficulty of having 60 components of a single manufacturer and model. As a result, less performance based maintenance will be done in favor of more time based maintenance, which does not appear to be the stated objective of the standard. BPA believes that there are other drivers of equipment reliability and that going simply by manufacturer make and model is too restrictive and almost forces the use of time based maintenance intervals. These time based maintenance intervals have been established by surveying utilities and taking the average maintenance interval of the surveyed utilities. BPA suggests it would be better to allow an alternate definition of Segment to include, for example, mechanical sudden pressure relays to be grouped as an item, provided the population has consistent performance across the population and provided the population is tracked by manufacturer and model. BPA believes this would allow performance based maintenance systems to be applied more broadly and would be more effective than using time based maintenance intervals. For example, provided an entity also tracks manufacturer and model and establishes consistent performance across the population, could an entity track the following groups as a population segment? 1. Mechanical Sudden Pressure Relay 2. Electronic Sudden Pressure Relay 3. Mechanical Buchholz Relay 4. Mechanical Sudden Flow Relay
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
Tri-State understands and approves of the removal since it was a "check the box" requirement and didn't help the reliability of the BES. However, we wonder how the auditors are going to confirm that an entity requested and used the correct information in determining applicability for automatic reclosers. What is the SDT suggesting to address this?
Yes
Yes
Yes

Individual
Joshua Andersen
Salt River Project
Yes
Yes
Yes
Yes
Salt River Project suggests that sudden pressure relays are not necessary for the reliable operation of the Bulk-Power System. Faults that would trip the sudden pressure relays would also trip other relays used for protection of the assets. Salt River Project recommends the removal of sudden pressure relays from this standard and recommends that the other relays be updated where necessary. Additionally, a requirement for the sudden pressure relays may persuade entities to remove or inactivate them so they are not subject to the requirements in this standard.

Additional Comments:

Austin Energy
Thomas Standifur

Austin Energy supports the comments submitted by Florida Municipal Power Agency (FMPA), and add the following thought for the SDT's consideration. The purpose of the Sudden Pressure Relay should be considered in the applicability of the requirements. In instances where a Sudden Pressure Relay is employed to protect an entity owned asset from damage by removing the asset from operation prior, and where the relay is not employed to protect the reliability of the BES, the Sudden Pressure Relay should be excluded from the requirements of this standard. For instance, a Sudden Pressure Relay used to remove a piece of equipment from service to prevent severe equipment damage and not being used to protect the reliability of the BES should be excluded from the requirements of this standard.