**Individual or group. (41 Responses)**
**Name (25 Responses)**
**Organization (25 Responses)**
**Group Name (16 Responses)**
**Lead Contact (16 Responses)**
**IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)**
**Comments (41 Responses)**
**Question 1 (35 Responses)**
**Question 1 Comments (35 Responses)**
**Question 2 (31 Responses)**
**Question 2 Comments (35 Responses)**

| |
|---|
| Group |
| Northeast Power Coordinating Council |
| Guy Zito |
| |
| Yes |
| |
| Yes |
| Referencing Applicability Section 4.2.6, the Balancing Authority has to notify and provide documentation to the appropriate entities in 4.2.6.1 and 4.2.6.2 that automatic reclosing maintenance is required. TO substations within 10 circuit miles will need to be identified by the Balancing Authority as well. To clarify Footnote 1 on page 4, suggest the following rewording: Automatic Reclosing as addressed in Sections 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close in three-phase fault not cleared for the length of a breaker trip-close-trip operating time does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied. In the Implementation Plan the SDT did a good job inserting the appropriate wording to remove a potential conflict with regulatory practice with respect to the effective date of the standard. However, the wording needs to be inserted in Section 4 of the Background Section. Review the Implementation Plan and insert the following words where appropriate: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." The Implementation Plan must be made available throughout the life of the Standard. |
| Group |
| Duke Energy |
| Colby Bellville |
| |
| Yes |

| |
|---|
| Duke Energy requests additional information regarding the Footnote 1 exclusion provision. As written, it is unclear as to what exactly is needed to provide demonstration for this provision, as well as the frequency of the demonstration necessary to remain compliant. For example, if an entity performs an analysis to prove that the exclusion was applicable to a specific Automatic Reclosing Relay, would the entity need to run another analysis ever again, or would an analysis only need to be done if there was a change to the Balancing Authority Area's system or the BES? Also, Duke Energy suggests that because Footnote 1 effectively acts as an exclusion, that the SDT consider placing the Footnote in the standard itself. |
| Yes |
| Duke Energy requests clarification from the SDT as to whom they envision identifying the newly acquired Automatic Reclosing Components, how they must identify, and what documentation is needed to show correspondence with an entity's maintenance program. Also, Duke Energy suggests that the SDT consider placing the Implementation Plan for Newly identified Automatic Reclosing Components in the standard itself, and not as its own document. |
| Group |
| MRO NERC Standards Review Forum (NSRF) |
| Russel Mountjoy |
| |
| No |
| Plase clarify what is meant by "BES elements at substations one bus away from generating plants". How is the one bus criterion applied at a generating station with power transformation and multiple voltages? The use of the words substation and "one bus away" leaves the definition open to interpretation when a plant is connected at one voltage class and there are reclosing relays at another voltage class. The higher or lower voltage class bus could be read as "one bus away" and yet at the same substation. It may be necessary to speak in terms of either substations or electrical busses. It may also be necessary to define how a different voltage class bus should be treated. Could a large power transformer between voltage classes be equivalent to 10 circuit miles of impedance? Was the reclosing only meant to apply at the same voltage class? |
| No |
| The implementation plan should be based upon the existing maintenance schedules for the affected BES components. |
| Individual |
| Thomas Foltz |
| American Electric Power |
| |
| No |
| Regarding 4.2.6.2 in the Facilities section, the verbiage used suggests that substations that are one bus away, but connected by a transformer instead of a line, would be in scope. This |

| |
|---|
| would seem technically inappropriate, as a transformer would typically have a higher impedance than 10 miles of line and therefore premature reclosing at these substations should not affect generators one bus away in these cases. If such substations were to be included, it would unnecessarily bring into scope many more reclosing relays than intended by FERC Order No. 758. AEP envisions voting affirmative on this proposed standard if our concerns regarding scope are eventually addressed. |
| No |
| AEP will reserve its comments on the proposed implementation plan until its concerns on scope are eventually addressed. Due to the current volume of standards development activity, AEP is not able to apply the same level of rigor to this request for comment as we would normally. As a result, the comments provided in this response are those we deemed the most significant, and do not necessary reflect all the issues that AEP may, at some time, choose to address. |
| Individual |
| Michelle D'Antuono |
| Occidental Chemical Corp. (Ingleside Cogeneration LP) |
| |
| Yes |
| Ingleside Cogeneration agrees with the distinctions that the project team has made to determine which automatic reclosing components may pose a risk to the BES, and therefore should be subject to PRC-005-3. Clearly those that are incorporated in an SPS have a direct reliability impact. However, it is reasonable to limit applicable to reclosing systems that reside at or near significant generation facilities. We also agree that an exclusion should be allowed wherever the relay owner can demonstrate that the generator protection scheme is configured to withstand a Fault time frame of twice the normal clearing time without severing the Facility from the BES. This is a very conservative risk threshold and properly focuses compliance resources on the most prevalent threats to BES performance. Lastly, the limits of the control circuitry functionality testing are also appropriate. The prior version of PRC-005-3 included testing through the breaker trip coils – which may also inadvertently lock out other ancillary functions. Since the only reliability concern is that the reclosing relay will misoperate in a manner that will result in a premature closing signal, it is appropriate that the functional test required by NERC focuses only on that point. |
| No |
| Ingleside Cogeneration believes that the one year time-frame given to incorporate all the components of Automatic Reclosers newly identified as applicable to PRC-005-3 due to a generation change in the BA footprint is insufficient. It is appropriate to require the PSMP to be updated with the new components by that date, but not to conduct the first full set of maintenance activities. Our primary concern is that Ingleside, as a Generator Owner, will not receive timely notification that a substantive change has been made. And although we are willing to reach out to our Balancing Authority on a regular basis – or to establish a notification process – this is not a coordination activity that either of us have historically |

| |
|---|
| pursued. Furthermore, the recloser relays maintenance is handled during planned outages. At the very least, we would need an additional three years to schedule and execute the Table 4 maintenance activities in a quality manner. Since a single miss to PRC-005-3 would result in a big dollar penalty, we believe that there is some reasonable leeway that should be provided. Four years beyond the date of the generation change is not excessive – particularly since the failure of reclosing relays has not been found as the cause of a major BES event, or even a common issue in less extensive failures. |
| Group |
| PacifiCorp |
| Ryan Millard |
| |
| Yes |
| |
| Yes |
| |
| Individual |
| Nazra Gladu |
| Manitoba Hydro |
| |
| No |
| Although Manitoba Hydro will continue to maintain our "negative" vote for this standard based on concerns from the PRC-005-2 version, we do offer the following comments to the SDT in regards to PRC-005-3: (1) Table 1-4(a), (c), (f) - Manitoba Hydro suggests that the maintenance activity for electrolyte level inspections would be more appropriately specified on intervals of six calendar months, rather than on a four month basis. It is our experience that maximum maintenance intervals of 6 months are adequate at addressing reliability. Requiring four month intervals would be needlessly burdensome to industry without achieving additional reliability benefit. Moreover, the maintenance activities which require inspections to be completed every 18 months will oblige entities to make an additional site visit every second year. In effect, entities are being asked to check equipment (e.g. electrolyte levels) on month 16, return on month 18 to check equipment components such as ohmic values, charge float voltage, etc, and then required to return again on month 20 to check electrolyte levels, which is excessive. Instead, Manitoba Hydro suggests a more manageable maximum maintenance interval of 4 calendar months for these types of maintenance activities (station dc supply voltage, electrolyte level and for unintentional grounds). |
| No |
| Although Manitoba Hydro will continue to maintain our "negative" vote for this standard based on concerns from the PRC-005-2 version, we do offer the following clarifying comments to the SDT regarding PRC-005-3: (1) General comment - the words "Automatic Reclosing Components" are both capitalized and de-capitalized throughout the document. For example, |

| |
|---|
| within the definition of a Protection System Maintenance Program (PSMP) the words are de-capitalized, but are then capitalized in PRC-005-3 R3. For consistency, Manitoba Hydro suggests selecting one or the other. (2) Definitions of Terms Used in Standard, PSMP - capitalize the word “component” for consistency with the rest of the standard. (3) Background 4, Retirement of Existing Standards, Implementation Plan for Requirements R1, R2 and R5, Implementation Plan for Requirements R3 and R4, Implementation Plan for Requirements R1, R2 and R5 and Implementation Plan for Requirements R3 and R4 - replace “Board of Trustees” with “Board of Trustees’” for consistency with other standards. |
| Individual |
| Travis Metcalfe |
| Tacoma Power |
| |
| Yes |
| Additional Comments- 1. In the definition of a PSMP, captialize ‘components’. 2. In the definition of a PSMP (including Supplementary Reference), capitalize ‘automatic reclosing’. 3. In the Implementation Plan, change “The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of first calendar quarter…” to “The existing standard PRC-005-2 shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter…” |
| Yes |
| |
| Individual |
| Alice Ireland |
| Xcel Energy |
| |
| Yes |
| We are supportive of the changes made. But we do have two additional comments: a. The inclusion of Table 4-2(b) in PRC-005-3 raises the concern of where this testing would have been required in PRC-005-2 and raises uncertainty about the SDT's intentions for the testing requirements for all the various possibilities for actuation of SPS mitigating devices. We were under the impression that row 1 of Table 1-5 in PRC-005-2 required 6 year verification of trip coils or actuators of circuit breakers or other SPS mitigating devices. What if an SPS calls for the closure of a normally open breaker and that close signal is accomplished via some means other than a reclosing relay? Where would the testing of such a breaker closure be required by PRC-005-2 or PRC-005-3? The way PRC-005-3 Table 4-2(b) is phrased it would appear that trip coil operations for circuit breakers in protection systems or SPS's would be required per Table 1-5, row 1 and that close coils that are parts of reclosing schemes are required per tested by Table 4-2(b), row 1, but there does not appear to be testing requirements for any other SPS mitigating devices such turbine runbacks, closure of normally open breakers, disconnect operators, etc. Please clarify testing requirements for SPS mitigating devices outside of breaker trip coils (Table 1-5, row 1) and close coils as utilized in SPS reclosing |

| |
|---|
| schemes (Table 4-2(b)) - e.g. turbine throttle valve runback, LTC blocking or enabling, closure of normally open breakers, MOD operation, etc., etc. This appears to be a reliability gap in both PRC-005-2 and PRC-005-3. b. The applicability of reclosing to the Generator Owner & Transmission Owner is dependent upon the GO & TO knowing the characteristics of the Balancing Authority. GOs & TOs do not have this knowledge. There should be an obligation of the BA to inform (and update as needed) the GO and TO of the gross MW value of the largest unit in the BA footprint (or determine the appropriate entity to update the GO & TO). This could be accomplished by adding BA's as an applicable entity to PRC-005-3 and adding a requirement for this notification of TO' s and GO's by the BA to PRC-005-3. Alternatively, the applicable entities for PRC-005-3 could be left as is and the requirement for BA's to notify TO's and GO's could be accomplished by adding a new requirement to a more appropriate standard. |
| No |
| The implementation plan for the initial implementation of the program allows for a gradual implementation of requirements R3 and R4 for reclosing relay maintenance activities for those relays determined to be in scope such that 30% must be compliant within 36 months of regulatory approval, 60% compliant within 60 months of regulatory approval, and 100% compliant within 84 months of regulatory approval. The additional implementation plan requires 100% compliance within the next following calendar year even in those circumstances where the retirement of the largest unit in the balancing authority would result in an entirely different set of reclosing relays to be in scope. For consistency, it would be far more reasonable for the additional implementation plan to be aligned with the requirements of the original implementation plan for R3 and R4. Specifically, entities should be compliant with R1, R2, and R5 for the newly in scope schemes at the start of the first calendar quarter 12 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area. For requirements R3 and R4, entities shall be 30% compliant within 36 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area, 60% compliant within 60 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area and 100% compliant within 84 months following notification of a change in generation necessitating additional reclosing relays be added to the maintenance program or change in the largest unit in the BA area. |
| Individual |
| Daniel Duff |
| Liberty Electric Power |
| |
| No |
| 4.2.6.1 uses the phrase "greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area" as one determinant for inclusion of relays into the standard. However, generators do not have a wide area view of the system, and cannot |

| |
|---|
| determine the gross capacity of the largest BES generating unit. Does this value include all generation which could trip simultaneously at a single generating location? All generation which is connected through a single step-up transformer? Further, changes outside of the control of a generator could move relays in or out of the program. If retirement of an asset lowers the gross capacity value of the largest BES generating unit, would relays immediately be pulled into the program? Finally, there is no requirement for the BA to provide the gross capacity value to generation owners. The BA should be added to the list of covered entities, with a requirement to provide to all entities in their balancing area notice of the gross capacity of the largest generating unit once per calendar year, and within 30 days of a change in this value. Another section should be added to the standard to list the implementation requirements for existing assets when a covered relay enters the program. |
| No |
| The program as written requires 30% compliance at 60 months. This implies two instances of 12-year maintenance have to occur in 5 years, or 19 years earlier than should be required. The plan should be changed to all relays must have the first maintenance completed by 144 months from the effective date of the standard. |
| Individual |
| David Jendras |
| Ameren |
| Agree |
| We agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference. |
| Individual |
| Bill Fowler |
| City of Tallahassee |
| |
| Yes |
| |
| Yes |
| |
| Individual |
| Michael Falvo |
| Independent Electricity System Operator |
| |
| No |
| The IESO believes that the analysis required by the Footnote 1 is out of the scope of PRC-005-3, which is to document programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the BES so that they are kept in working order. In addition, the analysis required by the Footnote 1 is vague and difficult to assess compliance. In the IESO's view, contingencies and related tests performed in transient simulations should be defined in |

| |
|---|
| the planning standards (eg. the TPL standards), instead of PRC-005-3 which is drafted for maintenance purposes. We suggest removing the Footnote 1 from the draft standard, or in case it is retained it should be revised to address the aforementioned concerns. |
| No |
| We appreciate the SDT’s effort to insert appropriate wording to remove a potential conflict with Ontario regulatory practice with respect to the effective date of the standard. However, there are still a couple of places where this insertion is missing. Please insert: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” prior to the wording “,or in those jurisdiction….” in Section 4 on P.2 and in the first paragraph under the Retirement of Existing Standards” on P.3. |
| Individual |
| Gerald Farringer |
| Consumers Energy |
| |
| No |
| Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes. |
| No |
| Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes. |
| Individual |
| Anthony Jablonski |
| ReliabilityFirst |
| |
| Yes |
| ReliabilityFirst votes in the affirmative because the modifications to this standard further establishes minimum maintenance activities for Automatic Reclosing Component Types and the maximum allowable maintenance intervals. ReliabilityFirst offers the following comments for consideration: 1. Table 4-2(a) and 4-2(b) - ReliabilityFirst seeks the technical justification for the maximum maintenance interval of 12 years for unmonitored control circuitry associated with Automatic Reclosing. 2. Applicability section 4.2.6.1 - ReliabilityFirst recommends adding the term “nameplate rating” to clarify which generating plants are required have Automatic Reclosing applied. Without this clarifier included, the term “total installed gross generating plant capacity” is subject to interpretation. For example, a plant |

| |
|---|
| may have multiple different values for its gross generating plant capacity but a plant will always have one static nameplate rating. The term “nameplate rating” is also consistent with the new NERC BES definition language. |
| |
| Individual |
| Tracy Goble |
| Consumers Energy Co. |
| Consumers Energy Co. |
| No |
| Consumer’s Energy Ballot member is voting NEGATIVE on Project 2007-17.2 Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) PRC-005-3 since the standard does not address how each entity is expected to obtain the required information “the gross capacity of the largest BES generating unit with the Balancing Authority Area” (in section 4.2.6.1) and know when it changes. |
| |
| Group |
| Pepco Holdings Inc & Affiliates |
| David Thorne |
| |
| No |
| 1) In section 4.2.6.1 the term “gross generating plant capacity” is used. We assume this refers to nameplate MVA ratings. To avoid confusion as to what unit of capacity (MVA or MW) is to be used to evaluate these criteria we suggest the phrase be clarified as “gross generating plant capacity (in MVA)”. 2) NERC’s System Analysis and Modeling Subcommittee (SAMS) recommended limiting the applicability of automatic reclosing within this standard to only those installations that would impact the reliability of the BES. Section 4.2.6.1 uses criteria based on the “gross generating plant capacity”. Neither the PRC-005-3 standard itself, nor the Supplementary Reference document explains how to calculate this gross capacity number. Consider a generating plant that has a total of 600 MVA of installed capacity connected to a 230kV bus. There are also units within the same “power plant” with 200 MVA of capacity connected to a 69kV bus. The 230kV and 69kV busses are interconnected by an autotransformer. The “gross generating plant capacity” is 800 MVA, however 200 MVA of this is connected below 100kV and is not considered BES generation. If it is not considered BES generation, then it should be excluded from the calculation of gross plant capacity in Section 4.2.6.1, as the loss of this generation would not directly affect the reliability of the BES. 3) In some switchyard arrangements generating units within the same power plant are connected to separate switchyard busses that are not connected together. This may be done for reliability reasons and to control fault current levels. In these situations, the calculation of gross plant capacity in Section 4.2.6.1 should be based only on the amount of generation directly connected to the individual bus, and not the total amount in the plant. 4) The NERC SAMS review concluded that automatic reclosing mal-performance affects BES reliability |

| |
|---|
| when “inadvertent reclosing near a generating station subjects the generation station to severe fault stresses”. The concern appears to be potential shaft torque damage, or instability, of rotating machines to automatic reclosing mal-performance. That being the case, generation sources that are not subject to severe fault stresses, such as inverter based generation, or static reactive sources (SVC’s, capacitor banks, etc.) should not be included in the calculation of gross plant capacity. However, since synchronous condensers are subject to the same fault stresses as synchronous generators they should probably be included in the gross plant generation calculation, providing they are interconnected at 100kV, or above. 5) To adequately address the concerns raised in the above sets of comments we suggest Section 4.2.6.1 be re-worded as follows to provide clarity and eliminate confusion on how to evaluate this plant capacity calculation: “Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity (in MVA) connected to that bus is greater than the gross capacity (in MVA) of the largest BES generating unit within the Balancing Authority Area.” In addition, a qualifying footnote defining “gross generating plant capacity” needs to be added as follows: “For application of 4.2.6.1 gross generating plant capacity is defined as the sum total of the nameplate ratings, expressed in MVA, of all BES rotating machine generating units (including synchronous condensers) that are connected to a common BES switchyard bus.” Also, specific examples showing how to calculate “gross generating capacity” should be included in the Supplemental Reference document in order to illustrate and clarity the issues described in the above comments. How will the applicable functional entities be aware of the largest (or change in the largest) BES generating unit within the BA area? |
| No |
| In order to verify the reclosing scheme performance on any newly identified busses, resulting from generation capacity increases, it may require scheduling sequential line outages on all BES lines emanating from the bus in order to test breaker auto-reclosing operations. Also, based on system operating conditions, these individual line outages may require coordination with certain generation outages. As such, due to the outage coordination necessary to perform this testing, it may not be possible to complete all testing and maintenance activities on these newly identified facilities by the end of the following calendar year. For this reason, we would suggest the following language (similar to that used in the first bullet of R3/R4 Section 5 of the April 2013 draft of the PRC-005-3 Implementation Plan) be used for the implementation plan for these newly identified Automatic Reclosing Components: “The responsible entities must complete the maintenance activities, described in Table 4, for any newly identified Automatic Reclosing Components, resulting from the addition, or retirement, of generating units; or increases of gross generation capacity of individual generating units or plants within the Balancing Authority area, by the first day of the first calendar quarter thirty-six (36) months following implementation of the capacity change, which resulted in the identification of these new Automatic Reclosing Components (or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage |
| Individual |

| |
|---|
| John Seelke |
| Public Service Enterprise Group |
| |
| No |
| Automatic reclosing systems, except for those which are an integral part of an SPS, are not part of Protection Systems that are designed and installed to detect and protect the BES from damage from faults and to keep blackouts localized, i.e., prevent cascades. Autoreclosing relays and systems are installed simply to automate an action by a system operator to close a breaker which automatically tripped, and with one specific possible exception, contribute very little to BES reliability. Besides the SPS, the one possible exception may be in those areas where by virtue of the transmission system configuration rapid reclosing of a tripped breaker is needed to minimize stability issues. PSEG agrees that reclosing relays may be significant to that specific circumstance, i.e., where rapid action is needed to avoid system instability. To identify those specific locations and circumstances and limit the inclusion of such relays to those where it is necessary, PSEG suggests that the drafting team incorporate language similar to that in the Transmission Relay Loadability Standard PRC-023-2 R6 which could be modified for PRC-005-3 to read as follows: “Each Planning Coordinator shall conduct an annual assessment to determine the specific locations/circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers with automatic reclosing relays must comply with the maintenance and testing requirements for such relays under this standard.” The Planning Coordinator has the expertise and skills to make this determination; many if not most BES asset owners do not. Power systems are designed to deal with permanent faults, not temporary faults. The extra cost of inclusion of many automatic reclosing relays in the maintenance and testing program would yield little or no benefit to reliability of the BES. Only those defined as essential by the Planning Coordinator should be included in this Standard. |
| |
| Individual |
| Andrew Z. Pusztai |
| American Transmission Company, LLC |
| |
| No |
| The selection criteria proposed to identify the reclosing relays that affect the reliability of the Bulk Electric System remains unclear. Please clarify what is meant by “BES elements at substations one bus away from generating plants”. How is the one bus criterion applied at a generating station with power transformation and multiple voltages? |
| No |
| The implementation plan should be based upon the existing maintenance schedules for the affected BES components. |
| Individual |
| Kayleigh Wilkerson |

| |
|---|
| Lincoln Electric System |
| Agree |
| MRO NERC Standards Review Forum (NSRF) |
| Individual |
| Jonathan Meyer |
| Idaho Power Company |
| |
| Yes |
| |
| No |
| The change in generation could bring in significant numbers of additional units to be added to the testing and maintenance procedures. We would prefer a percentage based approach similar to the implementation plan for the other table items in PRC-005-2. |
| Group |
| Dominion |
| Louis Slade |
| |
| No |
| The SDT did not address concerns relative to how an entity could determine the gross capacity of the largest BES generating unit within the Balancing Authority Area. Dominion suggests the SDT include a requirement that the BA post or make such information available to all entities in its area. The SDT did not address concerns that only planning entities are typically afforded access to the models or information, or have the technical skills necessary to be able to make the determination necessary to allow the exclusion included in footnote 1. |
| No |
| Given that most of the Maximum Maintenance Intervals appear to be in the 4-6 year range, we believe that implementation for newly identified Automatic Reclosing Components due to generation changes in the Balancing Authority Area should be extended to allow up to 36 months from BA notification of such change |
| Individual |
| Scott Langston |
| City of Tallahassee |
| |
| Yes |
| |
| Yes |
| |
| Group |
| SERC Protection and Controls Subcommittee |

| |
|---|
| David Greene |
| |
| Yes |
| 1) Please provide FAQ examples to clarify the meaning of ‘total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit’. Our take is the gross MVA for FAC-008 would be appropriate. But there are several MOD standards, including some pending FERC approval, that will prove MW and MVAR ‘capability’ not ‘capacity’. 2) We request that the SDT modify the FAQ 2.4.1 to include “typically IEEE Device No. 79” in referring to the Automatic Reclosing relay because this helps clarify the scope. Begin the answer with “Yes. Automatic Reclosing includes reclosing relays (typically IEEE Device No. 79) and the associated dc control circuitry.” |
| No |
| 1) We prefer that maintenance for newly identified Automatic Reclosing Components be completed within 3 calendar years. This is more consistent with the phased in approach that applies to the overall implementation. 2) We prefer a single document with the implementation plan; please combine the 2 documents. 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. |
| Group |
| North American Generator Forum Standards Review Team |
| Patrick Brown |
| |
| No |
| This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 4.2.6.1 “Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated SWYDs TO to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems? |
| No |
| 1. Regarding the implementation plan for this project, the SRT is concerned with the following: “For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3.” This would require two cycles of 12- |

| |
|---|
| year maintenance in five years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144 months from the implementation date of the standard. 2. The implementation plan states: “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.” However, If there is no specific ‘bookend’ required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance should be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is obviously short of a 12-year cycle. A Compliance Enforcement Authority could apply this in the following manner: Entity Y has four reclosing relays, all tested and installed on August 1, 2004. The ne PRC-005 Standard becomes effective on July 1, 2014. On August 2, 2014 entity Y could be found in violation if one of the four relays has not gone through the new 12-year required cycle. If the language was changed to 100% compliance by 144 months, with all the earlier steps eliminated, it would work. Specific language needs to be in place noting that no evidence shall be required for any testing prior to the enforcement date, and the 12-year clock starts on that day. The following change would need to be made also: “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until 288 months following the enforcement date of PRC-005-3.” |
| Individual |
| Louis C. Guidry |
| Cleco |
| |
| No |
| We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults. |
| No |
| We do not believe reclosing relays are protective devices and therefore are not subject to this level of oversight. Second, the strongest justification was that if the relay failed to operate correctly and reclosed instantaneously, the generator would be subject to additional fault duty. We have not seen such a failure and do not see the justification for including reclosing relays or restoration devices in a Protection System Maintenance & Testing Standard. Major storm events near the station or breakers failing to latch are far more likely to cause sequential faults. |

| |
|---|
| Group |
| Oklahoma Gas & Electric |
| Terri Pyle |
| |
| No |
| In the draft Standard and the Supplementary Reference, a lot of detail was deleted from the definition of Automatic Reclosing. The revised definition no longer includes the phrase "but excluding breaker internal controls such as anti-pump and various interlock circuits." Does this imply that those components are now included in the definition of Automatic Reclosing? In reference to these components, the Supplementary Reference document (in section 15.8.1) states that, "These components are not specifically addressed within Table 4, and need not be individually tested. They are indirectly verified by performing the Automatic Reclosing control circuitry verification as established in Table 4." The Standard needs to be explicit on what is and is not required to be tested as part of an entities PRC-005 maintenance and testing program rather than leaving it open to interpretation. In 4.2.6.1 of the Applicability section of the draft Standard, reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority Area. It would be helpful if the SDT provided some examples (including some that references how to address combined cycle units/plants) in the Suppementary Reference document to help entities understand and properly apply Section 4.2.6.1 of the Standard. |
| Yes |
| |
| Group |
| PPL NERC Registered Affiliates |
| Brent Ingebrigtson |
| |
| No |
| ) There are currently two NERC approved projects filed at FERC (PRC-005-1.1b and PRC-005-2). NERC should consider waiting to proceed with this project until the current projects are ruled on and FERC provides further direction. 2) For 4.2.6, for reclosing capability, it is unclear what functionality is to be tested. Please define. 3) For PRC-005-3 section 4.2.6.2, please provide the technical basis for this application of the Standard. Specifically, this application states for Automatic Reclosing: “Applied on BES Elements at substations one bus away from generating plants specified in section 4.2.6.1 when the substation is less than 10 circuit miles from the generating plant substation.” Please provide the technical basis/reasoning for the 10-mile criteria. At a recent North American Transmission Forum Workshop on Protection System Maintenance Program it was implied that the 10 mile rule is for cases where a generator has a short connection to another company’s substation. Please clarify if this is the case. 4) For PRC-005-3 section R1, consider adding the following language that is used for PRC-005-1.1b “each Generator Owner that owns a generation or generator interconnection |

| |
|---|
| Facility Protection System...” This is NERC-approved language that has been through the standards development process and has technical justification through Project 2010-07. 5) Please provide the technical basis for R1.1 which requires battery testing for DC Supply Component Type Protection Systems to be time based. 6) Table 1-2 of PRC-005-3 requires functional testing of non-monitored communication systems on a 4 month cycle. Please specify NERC’s criteria for the functional testing (what attributes to be tested). Additionally, specifically define monitoring criteria and data intervals for continuous monitoring of communications systems (to see if check back (fail/no fail) monitoring is adequate). 7) This standard presents compliance documentation uncertainties for applicable reclosing relays defined in Applicability Section 4.2.6.1 “Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area”. This standard now assumes that GO/TOs are going to coordinate and document that they have contacted the BA to determine the largest unit in the area and then determine if the reclosing relays are/are not applicable but does not mention it in the measures. How much coordination and documentation is required by a GO and its associated switchyards. Does the TO need to prove that the generation facility does or does not exceed the largest BES unit? Does this become part of a PRC-001 requirement to coordinate protection systems? |
| No |
| 1. Regarding the implementation plan for this project, the PPL NERC Registered Affiliates are concerned with the following: “For Automatic Reclosing Component maintenance activities with maximum allowable intervals of twelve (12) calendar years, as established in Table 4: The entity shall be at least 30% compliant on the first day of the first calendar quarter sixty (60) months following applicable regulatory approval of PRC-005-3.” This would require two cycles of 12-year maintenance in five years for 30% of your affected equipment. We recommend that the implementation plan be changed to require that 100% of the affected relays have one maintenance performed by 144 months from the implementation date of the standard. 2. The implementation plan states: “For activities being added to an entity’s program as part of PRC-005-3 implementation, evidence may be available to show only a single performance of the activity until two maintenance intervals have transpired following initial implementation of PRC-005-3.” However, If there is no specific ‘bookend’ required, and the cycle is truly a 12-year cycle, no evidence of testing or maintenance could be required prior to 144 months from the enforcement date of the standard; but the proposed implementation plan requires the work at 36 months, 60 months, and 84 months, which is short of a 12-year cycle. |
| Group |
| Southern Company |
| Wayne Johnson |
| |
| No |
| 1) We believe that there should be a Requirement for the BA to initially inform the TOs and GOs in their area which units are in scope. Minimally, there must be a requirement that the |

| |
|---|
| BA identify the ‘largest BES generating unit’ and inform all the TOs and GOs in their area. 2)Secondly, related to 1) above, there must be a requirement that the BA inform all the TOs and GOs in their area when a change occurs related to the ‘largest BES generating unit’. |
| No |
| Southern Company believes that the two implementation plans associated with the Standard are in conflict. It can be interpreted that all automatic reclosing components will be ‘newly identified’. As such they would be required to be completed by the end of the following calendar year. We believe that the intent was to have the initial applicable Automatic Reclosing Components to have the same phased in completion dates that were brought forward form PRC-005-2. If that was the intent, an potential conflict exists since after the initial phased in schedule up to 12 yrs is set, a change in the unit applicability could occur one year later which could in the case of ‘largest unit’ retirement bring many more locations into scope all of which would be newly indentified and be subject to the one calendar year requirement. Bottom Line is that the Implementation plan needs to be revisited. Related to the comment to #2 above, we do not specifically see a timeline identified to include the following: 1) Identification to identify the units and components covered. 2) Identification of the components that may be excluded per the Note. 3) Modification to the PSMP 4) Actual Implementation If the intent is for all this to be covered in R1 and R2, we question this for the following reasons: • Is this enough time for the initial steps noted above, and • This result in multiple dates for compliance with R1 and R2 |
| Individual |
| Brett Holland |
| Kansas City Power & Light |
| Agree |
| SPP - Robert Rhodes |
| Group |
| Hydro One Networks Inc. |
| Sasa Maljukan |
| Agree |
| IESO and NPCC RSC |
| Individual |
| Brian Evans-Mongeon |
| Utility Services |
| Agree |
| NPCC Reliability Standrds Committee |
| Group |
| ACES Standards Collaborators |
| Jason Marshall |
| |

| |
|---|
| No |
| (1) We find that the changes are non-substantive and do not present a problem. However, we continue to be concerned about modifying this standard when there is another version pending before the Commission. We believe it will only cause confusion. Given that this standard is historically one of the top ten most violated standards and the most violated non-CIP standard, industry does not need to be burdened with further confusion that will only cause additional violations. One example of the confusion is the implementation plan of the proposed draft. If the PRC-005-2 standard was already enforceable, the implementation plan could focus only on auto-reclosing which would avoid the confusion. (2) Because there were no general feedback questions asked and there is no other appropriate question to place our other concerns with the proposed standard, we are inserting them here. (3) The implementation plan creates confusion with dual conflicting parallel dates. The confusion is understood by comparing PRC-005-2 implementation plan to the PRC-005-3 implementation plan. For example, the implementation plan for PRC-005-2 requires the responsible entity to be at least 30 percent compliant on the first day of the first calendar quarter 24 months following applicable regulatory approval for maintenance activities with a three year interval. The PRC-005-3 implementation plan is identical. Thus, if FERC approves PRC-005-2 such that is has an effective date of June 1, 2014, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with three-year interval maintenance cycles by July 1, 2016. If FERC then approves PRC-005-3 such it has an enforceable date of September 1, 2015, the responsible entity will have to be 30 percent compliant with R3 and R4 for equipment with a three-year interval maintenance cycles by October 1, 2017. Thus, there will be two different conflicting dates for the 30 percent compliance level. Which applies? If the second applies, this is like resetting the compliance date. Furthermore, there is unnecessary confusion with the 30 percent compliant metric, as this could change from the two different implementation plans if additional equipment is installed during the implementation plan. There are too many compliance risks of having implementation plans overlapping or coming into effect in a short amount of time. This proposal mirrors the issues of the implementation plans with CIP version 4 and CIP version 5. FERC granted an extension in order to allow responsible entities to more efficiently utilize resources to transition to the next version. We, as an industry, should learn from this experience and not rush to the next version of the standard prematurely. (4) We disagree with the statement (second paragraph first sentence and first bullet) in the general considerations section of the implementation plan that states the responsible entities must be prepared to identify Automatic Reclosing components during the transition from version 2 to version 3. While we agree that this ultimately will be necessary at some point in the transition to prepare for the compliance date, we are concerned that an auditor could interpret this implementation plan as requiring the responsible entity to develop an inventory of Automatic Reclosing components prior to the effective compliance date. A standard cannot retroactively require actions to be completed prior to its effective date. This identification of Automatic Reclosing components presents serious compliance issues and we recommend striking it in its entirety. (5) We disagree with the statement (second paragraph first sentence and second bullet) in the general considerations section of the implementation plan that states the responsible entities must |

be prepared to identify “whether each component has last been maintained according to PRC-005-2 (or the combined successor standard PRC-005-3), PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0, or a combination thereof”. We do not have an issue if this statement applies only to the Protection System components because they have been under these standards for some time. However, this statement could be viewed as applying to Automatic Reclosing components and it should not because they have never been subject to any standard. While most responsible entities will have maintained their Automatic Reclosing components, they simply were not required to maintain them and, thus, the documentation may not be sufficient to demonstrate prior maintenance activities. Maintenance activities for Automatic Reclosing components are not required until PRC-005-3 is enforceable. (6) We do not understand why PRC-005-1b, PRC-008-0, PRC-011-0, and PRC-017-0 will not be retired for 156 months or 13 years. That is quite a long time for these standards to be effective in parallel. This poses a potential for double jeopardy and we recommend retiring these standards at the same time the new standard becomes enforceable. (7) We find the language in section 3 of the implementation plan for R3 and R4 confusing. That section proposes to require the responsible entity to comply with R3 and R4 for 30 percent of the Protection System components that are subject to three-year maintenance intervals. However, this language “or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage” is added as a caveat. We are unsure how to interpret it. Does this mean that if a generator has three-year maintenance interval that 30 percent of its Protection System components must meet compliance at the conclusion of the first succeeding maintenance outage or it is an exception and all of its Protection System components must meet R3 and R4 compliance obligations by the same date? (8) Section 4.2.6.1 of the applicability section of the standard is inconsistent with the proposed definition of the Bulk Electric System (BES) and may be inconsistent with existing definitions that vary by region. Since Inclusion I2 includes the generator and generator step up (GSU) transformer as part of the BES, what exactly would constitute the BES bus? The low side bus of the GSU transformer, the high side bus or some other location? All of these are part of the BES. This section needs further clarification. (9) Section 4.2.6.2 of the applicability section of the standard needs further refinement. What would constitute one bus away from the generating plant? What constitutes the plant? The electrical machine, turbine, GSU, and switchyard? What if there is more than one switchyard? What if the switchyard is not on the immediate property but short distance away? Some additional refinement would help to answer these questions. We suggest utilizing the GSU as demarcation point to help clarify. (10) The evidence retention section needs to clarify that the responsible entity is not required to keep “documentation of the two most recent performances of each distinct maintenance activity “during the initial implementation of the standard for Automatic Reclosing components. This clarification will help avoid the problems that occurred with PRC-005-1 when auditors requested evidence from before the effective date of the requirements. The bottom line is that a standard cannot be retroactive and cannot compel evidence from before the effective date. This needs to be clear. (11) The evidence retention period is excessively long, is inconsistent with the Reliability Assurance Initiative (RAI), and is inconsistent with the Rules of Procedure. Since some Automatic Reclosing component maintenance intervals are 12

| |
|---|
| years, retaining the two most recent performances of each maintenance activity could result in evidence retention periods of almost 36 years. Entire careers will be worked before this evidence can be destroyed. Given the length of time, it is highly likely that responsible entities will lose some of the documentation which will result in paper violations that do nothing to support reliability. This is contrary to the RAI which is trying move to a forward looking compliance model that provides reasonable assurance of compliance. Furthermore, the evidence retention period is longer than the six year audit cycle for TOs, GOs, and DPs which is inconsistent with section 3.1.4.2 of Appendix C - Compliance Monitoring and Enforcement Program of the NERC Rules of Procedures. This section is very clear that the evidence retention cannot exceed a period prior to the last audit. (12) We suggest that Table 4-2(a) should be clarified that it only applies to those Automatic Reclosing components that are at large generator plants or close to large generator plants per applicability section 4.2.6.1 and 4.2.6.2 respectively. Otherwise, there may be confusion when compliance and enforcement personnel look at the table. They may view that it will apply to all Automatic Reclosing components that are not an integral part of a Special Protection System (SPS) including those are not close to large generators. |
| No |
| (1) We agree with the need for the additional implementation plan but find it confusing. First, we think that the compliance date should be identified as some interval after the commercial in-service date of the change in generation or the official retirement date. Otherwise, there could be confusion in which year the newly applicable Automatic Reclosing components must be compliant. Consider a new unit begins testing on December 1, 2013 and goes commercial January 31, 2014. One could interpret the language in the implementation plan to require the maintenance activities to be completed by December 31, 2014 or December 31, 2015. (2) To avoid the confusion that occurred with PRC-005-1, the implementation plan should state very clearly that the initial maintenance activities must be performed by the compliance date and that no evidence of prior maintenance activities is required. In essence, the compliance date established in this implementation plan due to changes in generation and the overall implementation plan should be very clear that the compliance date established in these plans is the start of the initial interval. To allow the interval to start before the compliance date would be equivalent to making the standard retroactive. |
| Group |
| SPP Standards Review Group |
| Robert Rhodes |
| |
| No |
| In the definition of Automatic Reclosing a goodly amount of detail has been deleted from the definition. Does the excluded portion of the definition, specifically breaker internal controls such as anti-pump and various interlock circuits still fall under the standard? The reference document implies that they do, but the revised wording is not clear to us. In 4.2.6.1 reference is made to the total installed gross generating capacity of a generating plant which is then compared to the gross generating capacity of the largest BES unit in the Balancing Authority |

| |
| --- |
| Area. Shouldn’t the reference to the largest unit also state the installed gross capacity of the unit to prevent any confusion? Also, in selecting to use gross generation numbers, we wonder if consideration was given to generation values used in other standards such as BAL-002 and BAL-003 which tend to lean toward net generation values rather than gross. In the Supplementary Reference we suggest replacing the term ‘supervisor’ on Page 92 in Section 15.8.1 FAQ in the 7th line of the 1st paragraph in the response to the 2nd question with ‘supervision’. The sentence would then read ‘…applicability of associated supervision/conditional logic and the…’. |
| Yes |
| |
| Individual |
| Texas Reliability Entity, Inc. |
| Texas Reliability Entity, Inc. |
| |
| No |
| We feel that the proposed maintenance activities in tables 4-1 and 4-2 do not necessarily address all of the typical failure modes of reclosing relays and control circuitry associated with them and offer the following comments: 1) Definition of Automatic Reclosing: Is it the SDT’s intention that “Control circuitry associated with the reclosing relay” includes a separate sync check relay that may be used in the reclosing scheme? The definition is not clear and the SDT may want to clarify. 2) Table 1-3: The SDT may want to consider adding an activity to verify voltage signals are provided for reclosing relay sync check functions. 3) Table 4-2(a) and 4-2(b): The SDT may want to consider including activities to verify that auxiliary relays in the reclosing scheme (i.e. bus differential or breaker failure lockout relays) properly inhibit reclosing. The SDT may also want to consider including activities to verify sync check functions depending on the system design (i.e. hot bus-hot line, hot bus-dead line, etc.). These two activities are necessary to verify that the reclosing scheme will not issue a reclose signal when it is not desired. 4) Table 4-2(b): Suggest rewording the 2nd block to say “Verify all paths of the control circuits ***including all auxiliary relays*** associated with Automatic Reclosing…” |
| Yes |
| |
| Individual |
| Bradley Collard |
| Oncor Electric Delivery Company LLC |
| |
| Yes |
| |
| Yes |
| |
| Individual |

| |
|---|
| Ryan Walter |
| Tri-State Generation and Transmission Association, Inc. |
| |
| No |
| Tri-State Generation and Transmission Association, Inc. finds that Table 4-1 is too inclusive and should include a restriction for only automatic reclose relays/functions that are required for system stability, with a list of which those should be as per SAMS, such as SPS and near generation. Table 4-1, as written, captures more equipment than is necessary, creating an undue administrative burden with little, to no, benefit to the reliability of the BES. Adding a compliance liability for reclosing relays that do not impact system stability could lead to industry removing many of the reclosing relays used for expeditious restoration. This does not improve system reliability. Also, since the majority of reclosing functions utilizing microprocessor relays reside within the microprocessor protective relay, the documentation for this testing will be included within documentation already required and provided under Table 1-1. To provide a separate list and documentation for all BES microprocessor reclosing functions will create an undue administrative burden on industry with little to no value to the BES. Further, we recommend the applicability of reclosers is changed to “reclosers identified by the entity’s selection criteria to be critical to the operation of the BES per its Maintenance and Testing Program” to better align with FERC order 758 where FERC recommends “selection criteria should be used to identify reclosing relays that affect the reliability of the Bulk-Power System”. Tri-State suggests that Table 4-2(a), Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of an SPS, be removed in its entirety or a maintenance activity specific to the circuitry be defined. The maintenance activity required in Table 4-2(a) is not a maintenance activity that verifies the control CIRCUITRY. A close “command” is external to the hardware circuitry. Whether or not that command occurs, does not confirm the functionality of the close circuitry hardware. The timing test for a reclosing function is also usually included within the testing of the protective relay, which is part of Table 1-1 and Table 4-1, making this table slightly redundant to what already exists. A definition of “premature”, giving specific tolerances, will also be required, if kept within the text, to understand at what point a test would fail or a result would be viewed as “non-compliant”. Any test for a microprocessor instantaneous reclose would fail this requirement, as the close command is already present at the beginning of the sequence, hence being “premature”. A PASS test result showing the reclose command was initiated within the tolerance of the relay but prior to the setting could be viewed as “premature” and be interpreted as “non-compliant”. A FAIL test result showing the relay closed well out of the manufacturer tolerance but after the setting would be viewed as “compliant”. If the text and Table remain, the statement: “Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry” should be changed to, “Verify that the close circuitry operates per engineering settings, and not sooner than (tolerance) of the setting.” |
| No |
| "Prior to the end of the following calendar year" is a very ambiguous implementation plan and could require entities to be compliant anywhere between 12 and 24 months. TSGT |

| |
|---|
| recommends that the implementation period state 18 months from the first day of the quarter following component identification. |
| Group |
| Colorado Springs Utilities |
| Kaleb Brimhall |
| |
| No |
| 1.Concerning facilities, would a reliability based method of determining covered facilities more likely better serve the reliability of the BES versus the generation based cap method under 4.2.6? 2.With no standard requiring re-closing relaying be in place, there will be a tendency to disable all re-closing relays to avoid facilities coming under this standard. |
| Abstained from commenting on this question. |
| Individual |
| Michael P. Moltane |
| ITC |
| |
| No |
| 4.2.6 references a footnote 1 that is an exclusion. How can an exclusion be put into a footnote? It should be up in the standard, not in a footnote. Regarding 4.2.6.1 for generating plant substations that have generator outputs at separate kV levels where the switchyards are not normally tied together are they treated as separate generating plants? Same question for locations that have generator outputs where the switchyards are not directly tied together. For a location that has a couple Balancing Authority Areas over it is the largest BES generating unit determined by the largest Balancing Authority Area? |
| Yes |
| |
| Individual |
| RoLynda Shumpert |
| South Carolina Electric and Gas |
| Agree |
| SERC PCS |
| Group |
| Western Area Power Administration |
| Lloyd A. Linke |
| |
| No |
| Further clarification and definition is required regarding the application of the standard to “premature” closing. Specifically, what is the definition of “premature” and why does the standard not refer to inadvertent or incorrect auto reclosing. Facilities Section 4.2.6.2 applies |

| |
|---|
| to automatic reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit miles from the generating plant substation. This Section should be clarified and should not include BES elements at those substations connected at a different voltage than the incoming generation circuit. The impedance of any transformation should represent sufficient isolation. It should be clarified that dc control circuitry and power circuit breaker close coils are only included with automatic reclosing that is an integral part of a SPS. |
| Yes |
| |