Individual or group. (63 Responses)
Name (43 Responses)
Organization (43 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (63 Responses)
Question 1 (56 Responses)
Question 1 Comments (58 Responses)
Question 2 (54 Responses)
Question 2 Comments (58 Responses)
Question 3 (52 Responses)
Question 3 Comments (58 Responses)
Question 4 (50 Responses)
Question 4 Comments (58 Responses)
Question 5 (0 Responses)
Question 5 Comments (58 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
We agree with the requirements as revised, but do not agree with Measures M2 and M3. a. Measure M2: The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. b. Measure M3: The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated.
No
We agree with the requirements as revised, but do not agree with the Measures. Measures: The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. The term “investigative

action(s)" is ambiguous even given the example cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard.
a. The "Effective Dates" section of the standard is confusing as it suggests no regulatory (i.e. FERC) approval is required in Western Interconnection and offers both twelve and twenty-four month timeframes. b. Applicability Section – Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs a similar function when initiated by abnormal voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. c. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. d. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. e. VSL for R3: Second condition under SEVERE - similar comment as for the VSL for R1 preceding. f. The SDT should reconsider the need for the defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. The comment report indicated that 4 commenters representing 24 individuals requested clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing the redundant new term.
Group
Puget Sound Energy
Dianne Gordon
No
a) Misoperation Definition #3 (Slow Trip – During Fault) would require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. b) Misoperation Definition #4 (Slow Trip – Other Than Fault) would also require the running of system studies to test for possible system

instability. This (and/or other expectations) should be spelled out in the Application Guidelines. c) For #2 & #4 sections of the Misoperation Definition as well as under Facilities (4.2.2) - UFLS/UVLS both should specifically be mentioned together. d) It should be clarified that non-fault tripping protection schemes as described in PRC-004-3 do not include RAS/SPS (and that RAS/SPS will be covered in PRC-016). e) It should be clarified in PRC-004-3 that UFLS/UVLS are not specifically part of the RAS/SPS definition (even though this is spelled out in the NERC glossary). Otherwise, it all can be quite confusing. f) In all six parts of the Misoperation Definition, the phrase "…where tripping for protection purposes is involved" could be included for clarity.
Yes
Yes
No
a) Application Guidelines could have more specificity, in addition to examples. For example, in #4 (Slow Trip – Other than Fault), it should be spelled out that each possible Misoperation should be studied to test for possible effects on system stability. Other specific expectations, if any, should also be spelled out. b) In addition, "Other than Fault" should be clarified and explained together with the definition of SPS/RAS, which are excluded from PRC-004. (SPS/RAS are defined as non fault protection schemes). c) UFLS/UVLS should always be mentioned together in PRC-004-3 (unless both are not included). d) Should sync check and breaker failure be considered in the Application Guidelines – what category do these fall into? e) In all six parts of the Misoperation Definition, the phrase "…where tripping for protection purposes is involved" could be included for clarity.
a) Under Facilities on p.5, UFLS /UVLS should both be listed, if intended. The order of facilities (specifically content of 4.2.1 and 4.2.2) should be swapped – so that everything INcluded comes before everything EXcluded. b) There should be a whole section clarifying exclusion of SPS/RAS (but inclusion of UFLS/UVLS). Or….the definition of SPS/RAS should be changed to include UFLS/UVLS. c) A Misoperation Process Benchmark table of reporting functions and dates should be provided to entities. This would greatly facilitate retention of misoperation timeline evidence (for audits, self-cert, data requests). The Misoperation Process Benchmark table structure could be provided by the Regional Entities such as WECC in an updated misoperation Criterion as an Appendix. A suggested list of Benchmark dates is as follows: 1. date of Interrupting device operation, 2. date of identification of misoperation, 3. date other owners of Protection System (of BES interrupting device operation) notified, 4. date of identification by notified entity whether its device caused a misoperation, 5. date the cause of misoperation investigated/found, 6. date of further investigation (if cause not found) 7. date of Corrective Action Plan (CAP) development 8. target CAP completion date(s), actual CAP completion date d) Finally, it is recommended that Quarterly Misoperation Reporting be changed over to a "Data Request" sooner than the effective date of PRC-004-3. It is stated on page 5 of the proposed PRC-004-3, that the currently reporting system is "not optimal to establish consistent metrics for measuring Protection System

performance”. Perhaps the ERO Reliabililty Assessment and Performance Analysis Group could release an updated recommendation letter for Misoperation Reporting. It is also recommended that the Misoperation “Data Request” occur once per year.
Group
US Bureau of Reclamation
Erika Doot
No
The Bureau of Reclamation (Reclamation) requests that the drafting team clarify the bounds of the Composite Protection Systems definition. Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems.
Yes
Yes
No
Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems.
Reclamation thanks the drafting team for their efforts refining the standard and providing the examples in the Application Guidelines.
Individual
William H. Chambliss, Member, Operating Committee
Virginia State Corporation Commisison
No
Minor suggestion in Parts 1 and 2 "Faliure to Trip." I suggest changing the phrase "failure of a Protection System component" to "failure of any Protection System component." Although it may be a remote possibility, more than a single component may fail, while the Composite Protection System as a whole acts correctly.
No
R1 remains very unclear to me. The text requires a TO, GO or distribution provider to "identify whether" its component caused a misoperation, but Subparagraph 1.3 requires, as a necessary condition to such identification that the "BES interrupting device owner [has] identified" that its component caused the failure. This is circular.
Yes

I have one wording suggestion for R3. I suggest moving the words "shall identify" from their present location to follow immediately after "Requirement R2." The sentence would then read "Each TO, GO and Distribution Provider that receives notification pursuant to Requirement R2, shall identify within the later of 60 days.....device(s) operation, whether its Protection System component(s) caused a Misoperation."
Yes
Under R5, the owner of a Protection System component that causes a Misoperation shall either develop a CAP or "Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability....." I wonder whether the Requirement should identify to whom and by what manner any such "declaration" should be made?
Group
JEA
Tom McElhinney
Yes
Yes
R1 & R3 both need an exclusion for any declared natural disasters. We also believe that the 60 day timeframe identified in R5 to develop a Corrective Action Plan and evaluate applicability is not sufficient to consider applicability to other PS, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. We recommend this be changed to 180 days.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration, L.P./Occidental Chemical Corporation
No
Ingleside Cogeneration, L.P. (“ICLP”) agrees that the definition of “Composite Protection System” properly captures the concept proposed by the project team. It reflects an intent that a Misoperation is determined by evaluating the actual performance of the primary, secondary, and pilot systems in totality against the expected performance. Evaluations of individual schema failures are of little value when built-in redundancy takes over to protect the local system – exactly as the designers intended. There is still discomfort with the definitions of “Slow Trip – During Fault” and “Slow Trip – Other Than Fault” – particularly in those cases where the design responsibility is out of our hands. For example, when PRC-024-1 takes effect, Generator Owners will have little control over the expected performance of

voltage and frequency-responsive Protection Systems – provided the relays are set in accordance with the standard. This means that the definitions need to include a statement that any composite Protection System operation that reacts consistently with the parameters (settings) established in any other NERC standard cannot be a Misoperation. Secondly, unless notified by the Transmission Planner or Planning Coordinator, ICLP will not know that the Misoperation of one of our Protection Systems will lead to BES "voltage or dynamic instability." The two definitions seem to recognize that the GO may not be in a position to be identify such critical Protection Systems, but can be read otherwise. Similar to the previous issue, we believe that as long as we correctly supply modeling data to the TP and PC in accordance with other NERC standards, the responsibility to identify susceptible Protection Systems remains with the planning entities.
Yes
ICLP believes that the latest draft of PRC-004-3 corrects a gap where a delayed investigation by one entity could lead to a finding of a violation on the other. Requirements R2 and R3 address this potentially unfair scenario.
Yes
ICLP appreciates the precise language used in Requirement R4 – which allows sufficient time to investigate a Misoperation, while limiting it to within reasonable bounds. We agree that if a cause cannot be found through good faith investigation within two calendar quarters, there is little benefit to pursuing the case further.
Yes
ICLP is concerned that Compliance Enforcement Entities' interpretation of PRC-004-3 will evolve over time – particularly as new Protection System vulnerabilities are found through the evaluation of Misoperations. In addition, the need for greater numbers of measuring points and the increased granularity of Disturbance data will naturally grow as relay schemes become more and more complex. This means that a clear expectation of the requirements for Disturbance Monitoring Equipment (DME) must be established up front in a binding fashion. We accept the project team's assertion that PRC-002-2 (presently under development) is the proper vehicle for the identification of required DME locations, but would like to see a clear tie to PRC-004-3. Otherwise it is easy to see that CEAs may decide at a future date that Misoperations' reporting needs are the driving factor for DME, not PRC-002-2.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes

Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
No
Throughout the draft standard (and definition of Misoperation), the term “Composite Protection System” is used while in other portions only the term Protection System is referenced. For example, within the definition of “Misoperation”, items one through four use the term “Composite Protection System” while items five and six use the term “Protection System”. Another example is Requirement R1, Part 1.1 references the term “Protection System” while Part 1.2 references “Composite Protection System”. ReliabilityFirst request the SDT’s rationale on the appropriateness of the use of these terms.
No
The term “BES interrupting device” is used throughout Requirements R1, R2 and R3 though it is only defined within the Application Guidelines section. In order to provide clarity and avoid potential interpretations of what constitutes a “BES interrupting device”; ReliabilityFirst recommends the SDT propose this as a new definition which would be added to the NERC Glossary of Terms. ReliabilityFirst recommends the following definition from the Application Guidelines for consideration: “BES Interrupting Device - A BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current.”
No
ReliabilityFirst has a number of concerns with Requirement R4. First, from compliance/enforcement perspective, Requirement R4 is not sufficiently distinct from Requirements R1 and R3 (it creates a “double jeopardy situation”). For example, Requirement R3 requires the responsible entity to “…identify whether its Protection System component(s) caused a Misoperation”. As written, if the responsible entity fails to “…identify whether its Protection System component(s) caused a Misoperation” this could be grounds for a possible violation of Requirement R3. This is evident in the associated Violation Severity Levels where failing “…to identify whether or not a Misoperation its Protection System component(s) occurred” is a Severe Violation. This is in direct conflict with Requirement R4, which gives the responsible entity additional time to perform investigation actions to determine the cause of the Misoperation. ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish but from a compliance/enforcement standpoint it will cause issues. Second, as already noted, ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish, but notes that there is no ending time period associated with how long the responsible entity has to complete the investigation. As

written, a responsible entity can hypothetically drag out the investigations and never officially complete the investigation. ReliabilityFirst believes in order to close the loop, the responsible entity should be limited to four calendar quarters to complete the investigation (i.e., either identification of the cause(s) of the Misoperation or declaration that no cause can be identified). To address the two concerns, ReliabilityFirst recommends including similar language as noted in Requirement R4 as sub parts in Requirement R1 and R3 along with including an ending completion timeframe as well. The following is an example for consideration for Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. If the cause(s) of the Misoperation cannot be determined, the Transmission Owner, Generator Owner, and Distribution Provider shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters, but for no more than four calendar quarters after the Misoperation was first identified, until one of the following actions completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
We suggest revising #6 Unnecessary Trip –Other Than Fault: replace the 2nd sentence as follows: Current wording: “A Protection System operation that is caused by on-site maintenance, testing, …is not a Misoperation” Suggested wording: “A Protection System operation that is related to on-site maintenance, testing, … is not a Misoperation”. This provides some flexibility to exclude operations not directly caused by on-site activity, but is a consequence of such activity.
No
There appears to be a gap between R1 and R2 for the case when an interrupting device operates, but the interrupting device owner does not own any part of the Protection System(s) that tripped or may have tripped the device. The assumption in the draft is that the interrupting device owner also owns a portion of the Protection System, but this may not always be true.
Yes
No
The examples 8a and 8b under Control Functions should be clarified to help entities make proper distinctions between control functions and protective functions of reverse power

relays. We suggest the wording in the paragraph following Example 8b be revised as follows: Current wording: In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit. Suggested wording: In the examples above, the standard is not applicable because the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System to protect turbine-generators from motoring. Entities often take advantage of this functionality and use the Protection System's reverse power function as a part of a normal procedure to shutdown a generating unit. However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit.
Individual
Shirley Mayadewi
Manitoba Hydro
No
(1) Manitoba Hydro believes that the definition of Misoperation needs to be re-written for the following reasons: a. It is not clear whether the six categories of Misoperations is exhaustive. The definition should be revised to clarify this. b. Under category 3, it is not clear if the cited example is the only type of Misoperations. c. Use of the phrase "slower than required" in category 3 and 4 of the definition is unclear and does not capture the intended meaning identified in the Application Guidelines. The Guidelines state that "required" actually means as intended by the owner. Thus, this terminology should be used. d. Based on the numerous examples in the Guidelines of what is and is not a "Misoperation", as well as references in the Guidelines to the effect that SMEs recognize that judgment must be used, the definition itself should clearly incorporate the notion of judgment by the owner. While the first sentence of the definition refers to intention, it does not specify whose intention (manufacturer, designer, operator..?) e. The sentences about component failure are out of place given that the definition of Composite Protection System is the total system, not individual components, and given that the first sentence of the definition refers specifically to failure of the Composite Protection System. f. The word "intended" has been replaced with "required" even though the Application Guideline states that the term "required" is intended to refer to the objective of the owner. If this is the intended meaning, then the standard should use the wording "as intended by the owner". The words "as required" are too vague and may be interpreted to mean as required to ensure the reliability of the BES. (Could it also mean as required by the designer / manufacturer or some other entity?) (2)

Revise the definition of Composite Protection System to “The total complements of the Protection System(s) that function collectively to protect an Element, such as A and B system, any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.”
Yes
No
(1) For R4, Manitoba Hydro does not think that there is a need to perform investigative actions to determine the cause of the Misoperation at least once every two full quarters. Repeated investigative actions would not be productive in identifying the cause. We propose this requirement to read as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation, until one of the following is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.”
Yes
(1) PRC-004-3, Application Guidelines, Extenuating Circumstances - for clarity, replace the word “says” with the word “reads”.
(1) R4, second bullet - for consistency with the previous bullet, rephrase to read “A declaration that no cause(s) were identified.” (2) R5, second bullet - because it’s possible that a single corrective action can be taken, add brackets around the “s” in the word “actions”. (3) R6 and M6 - for consistency with other requirements in the standard, replace the word “actions” with “corrective action(s)”. (4) R1 and R2 a. Use of the past tense (i.e. "that operated") is inappropriate for statutory / regulatory standards. The wording should be: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device shall, within 120 calendar days of the operation of the BES interrupting device...". b. Similarly, in R2.2 and 2.3 , the word "determined" should be replaced with "has determined". c. Use of the word "when" implies a time frame. Given the intent, it would be clearer to use the phrase "under the following circumstances". (5) R5 - for the reasons identified above, the use of past tense should be changed to:" Each Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System Component that causes a Misoperation ...". (6) The wording of R6 makes the compliance obligation unclear. Part of the requirement requires implementation of a CAP. However, another part of the requirement allows updating and changing the CAP. Accordingly, it can be inferred that some deviation from the CAP, and thus failure to implement the CAP, will still be considered compliance. A review of the Application Guidelines also confirms that rescheduling actions under the CAP is permitted in at least some cases. The criteria for acceptable revisions should be clarified in R6 (ex.- do they need to be beyond the reasonable control of the Responsible Entity?).
Individual
David Kiguel

David Kiguel
Yes
No
The standard should require that the Connection Agreement(s) among owners must address the procedures and potential dispute resolution for the case of 2 or more owners involved in the Misoperation investigation and CAP.
As written, the draft standard leaves a void that should be filled. A mechanism must be provided to allow for verifying that the conclusions of the investigation are correct, the CAP is appropriate and overseeing its completion within the planned time. Typically, this would be a responsibility that could be assigned to the Reliability Assurer (RA) as defined in the BoT approved Functional Model. The FM definition of RA fits this role well. However, since no entities are registered as RA at this time and it is unlikely there will be in the future, a second choice would be assigning such responsibility to the Planning Coordinator (PC). Suggest adding an additional requirement assigning such responsibility to the RA (or the PC if the SDT decides so): Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall submit its investigation report and CAP documentation to the Reliability Assurer (or Planning Coordinator) that has responsibility for the area in which the associated devices are located, within 21 calendar days of their completion. The RA (or PC) shall review and either approve or provide comments within 60 calendar days of the submission.
Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
Yes
Yes
Individual
Russ Schneider

Flathead Electric Cooperative, Inc.
No
I do not like adding composite to the definition of protection system. This seems to broaden what is understood as a protection system and may impact testing and maintenance programs unnecessarily. I suggest sticking with the way it was before this redline change.
Yes
No opinion on this change.
No
I do not believe that UFLS equipment should be included under this standard.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
We strongly believe that the drafting teams need to understand how the standards they are developing will interact with other NERC standards and documents. There may be unintended consequences when the relationships between two standards or other NERC documents are not foreseen. Regrettably, the SDT for the new BES Definition failed to take into account the substantial impact of its product on the various standards that would be applied to the new BES elements. Therefore it is critical for the PRC-004-3 SDT to take a step back and anticipate the effect of the new BES definition on this standard. The case in point is the addition of dispersed generators to the BES. We remain very concerned with the effort that will be required to comply with this standard in light of the new BES facilities that are included in the new BES definition, especially dispersed generation. It is wind that especially troubles us. We have about 200 wind turbine generators in our fleet, all less than 2 MW in size. Wind makes up less than 5 % of our generation capacity. Yet, in terms of the sheer number of generators, the number of wind units is roughly 5 times the number of other larger generators in our fleet. Of these 200 wind generators, 90% will soon become BES generators due to being aggregated in facilities above 75 MVA. It is the outsized impact of these wind turbines that will have a huge effect when we are required to analyze in depth each protection system operation of these wind generators in order to comply with PRC-004-3. This effort will be enormous, and yet the reliability benefit is negligible. The valuable technical resources available at my company, and at many other companies with even larger amounts of dispersed generators, are not best utilized by applying this standard at the level

of individual wind generators, and other similar small dispersed generators. To allow entities to focus limited technical resources on efforts that truly enhance reliability, the SDT should revise the Applicability to specifically exclude small dispersed generators, and only apply it where the aggregated generation exceeds 75 MVA, that is, to the collector bus and transformer (with the high-side winding operated at or above 100 kv) used to connect to the transmission system. We believe the extra time it takes to think this through will be worthwhile to the industry, and may prevent inadvertent outcomes that may not serve the overall reliability of the bulk power system.
Individual
Scott Bos
Muscatine Powerand Water
Yes
No
To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, MP&W proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden. Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard.

No
MP&W believes that there are many potential forms of “owners” and that “owners” needs to be modified to read, “other NERC registered applicable entities” to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don’t have any impact on the operation of the protection systems.
Yes
MP&W is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. MP&W also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue.
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
No
To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, the NSRF proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden. Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: Also of note is the Table’s use of the term “Calendar” in the column for “Maximum Maintenance Interval.” The PSMT SDT deemed it necessary to include the term “Calendar” to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance

schedules to be missed by a few days or weeks. The PSMT SDT chose the term “Calendar” to preclude the need to have schedules be met to the day. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard.
No
The NSRF believe that there are many potential forms of “owners” and that “owners” needs to be modified to read, “other NERC registered applicable entities” to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don’t have any impact on the operation of the protection systems.
Yes
: The NSRF is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. The NSRF also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
ATC agrees with the new and revised definitions, but recommends additional clarification around Slow Trip. Would a study be needed to indicate where high-speed performance was previously identified for a Slow Trip? The Slow Trip definitions infer that in order to correctly or incorrectly declare a Misoperation, a study would need to occur. Such study would need to pre-date the operation.
Yes
No
ATC’s experience has been that the cause of a Misoperation is determined within the first couple months following its occurrence. If the cause is not found in that time, it is unlikely to be found. Relative to R4, the parameters around investigative actions are not very productive, as revisiting the same information after an extended period of time does not typically lead to determining a cause. ATC recommends removing the language in R4 that speaks to investigative steps “at least once every two full calendar quarters after the Misoperation was first identified.”
Yes

Individual
Martyn Turner
LCRA Transmission Services Corp
Yes
Yes
Yes
No
LCRA TSC recommends the SDT address the topic of temporal aggregation within the Application Guidelines. For example, if a transmission line over-trips for an out-of-section fault three times in a 2-hour interval, perhaps due to persistent storm activity before a relay setting adjustment can be made, does this count as three misoperations, or can the three events of a similar nature and cause be “collapsed” into a single misoperation? Some guidance in this area would be helpful in order to allow entities to be consistent in reporting. LCRA TSC recommends some way to collapse/combine misoperation events of a similar nature within a short, defined timeframe.
no
Individual
Oliver Burke
Entergy Services, Inc.
Yes
There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate? The definition of Composite Protection System is still vague to this. Suggest the below definition: The total complement of the Protection System(s), with respect to the protective relay of interest, that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.
Yes
Yes
Yes

Look at response to question one.
Required Protection System Misoperation identification and evidence in support of R1 could be interpreted to include all scheduled or manual interrupting device operations, which we believe is not and should not be the intention. Either way, suggest rewording R1 to include the applicable Protection System governing criteria by integrating R1.1 (revised) into requirement R1 as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated due to a Protection System operation or a Protection System failure to operate as designed shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when:”
Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes
Yes
Yes
Individual
Thomas Foltz
American Electric Power
No
AEP recommends replacing “high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability” with “the lack of high-speed performance resulted in voltage or dynamic instability”. The draft does not specify who is responsible to perform the identification, and adding “Planning Authority” would create a de facto TPL requirement.
No
1) AEP recommends revising R1 section 1.2 as follows to recognize that a BES interrupting device may be part of multiple Composite Protection Systems: “The BES interrupting device owner owns all or part of the Composite Protection System(s); and”. 2) AEP recommends revising R2 section 2.1 as follows: “The BES interrupting device owner shares the Composite Protection System(s) ownership with any other entity; and”. 3) AEP recommends adding the

following footnote to the "entity" reference in R2 section 2.1: "In this context, "entity" denotes functional entity. A Composite Protection System owned by different functional entities within the same registered entity satisfies the R2 section 2.1 criteria." 4) AEP recommends adding the following footnote to the "entity’s" reference in the first bullet of R5: "In this context, "entity" denotes functional entity". 5) AEP recommends adding the following footnote to the “120 calendar days” reference in R2 and R3: “This timeframe may be extended, for operations occurring within a specified time period, by the Regional Entity if it determines that extenuating circumstances such as a natural disaster make it impractical to complete R1 or R2 within the allotted timeframe”.
Yes
AEP recommends replacing “at least once every two full calendar quarters after the Misoperation was first identified” with “at least once every six month period after the Misoperation was first identified”.
No
1) AEP recommends adding an example to the applications guideline to illustrate whether repeated operations/misoperations which occur during the same automatic reclosing sequence need a separate identification under R1. 2) AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a “slow trip” type misoperation. 3) AEP recommends adding an example to illustrate how breaker failure fits into composite protection system. 4) AEP recommends adding an example where a misoperation is initially identified, but subsequent investigation (after 120 days) reveals a misoperation did not occur.
AEP believes the draft is very close to being ready for final ballot. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. Our negative vote does not reflect disagreement on the direction or intent of the standard. Rather, it is driven by a number of smaller issues that, in total, would prove problematic in consistently applying the standard.
Individual
Don Schmit
Nebraska Public Power District
Yes
Please clarify the following; the composite protection system also includes the potential transformers, current transformers, battery bank and charger?
Yes
Yes
No

The application guidelines state: “The CAP is complete when all the documented actions to resolve the specific problem (i.e.,Misoperation) are completed which may include those actions resulting from the entity’s evaluation of other locations, if not addressed through a separate CAP.” In the example R6b it appears the CAP is completed and a program was established for corrections at other locations. Please clarify if a program to address other locations is or is not required to be tracked as part of PRC-004 evidence. In the example, it appears the program for other locations does not need to be tracked for PRC-004 evidence. Is this up to the entity to determine?
It seems like the scope for the CAP that must include an evaluation of other Protection Systems including other locations to be completed is very open ended. The concern is what an audit team’s latitude will be with reviewing and accepting or not accepting the subjective nature or these evaluations for other locations. Can the SDT comment how an evaluation that was completed for other locations as part of a misoperation might be addressed in an audit? For example, if a misoperation occurs due to a setting error and an entity decides not to review every relay setting on their system is it possible for an audit team to disagree with this evaluation and create any potential violations? It is recommended the section 1600 Misoperation Draft Template language should match PRC-004-3. It would be quite odd to have the evaluations requirements and a data submissions request use different language. The portion of R6 that states “and update each CAP if actions or time tables change, until completed” seems excessive and granular in nature and adds a lot of detail tracking and difficulty in auditing. It is enough to require a corrective action plan be implemented and close the plan when the final objectives are completed. R4 provides the long term tracking and scheduling. This portion of R6 should be removed. Another option would be to use similar language as in R4.
Individual
Chris Scanlon
Exelon
Yes
We support the definition for Composite Protection System.
No
Please address who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. Otherwise we have no concerns with R1. For R2 and R3, the date timeframes for a shared responsibility Protection System to a common interrupting device short cycles the non-owner of the interrupting device. A suggestion for shared responsibly; With R2 - the BES device owner should notify the Other Protection System owners within 30 calendar days of the operation and the device owner has 120 days calendar days to identify

if it's Protection System caused a misoperation. For R3, the notified Protection owner should then have 120 from notification to identify if its Protection System misoperated. This time frame for R3 would provide the non-owner sufficient time for any scheduled outages to make a determination.
No
How soon after a misoperation can a declaration of no cause be submitted? Exelon agrees that a prompt investigation of the event should occur and prudent corrective action be initiated as detailed in the new Requirement R4; however, if the Standard is allowing a provision for continued investigations then the other requirements in the Standard should align. Requirement R4 needs to be modified or R1 needs to be modified to align with each other. The current wording in R4 provides a requirement that cannot be met unless the entity is not in compliance with R1. R3 provides the wording such as "cannot rule out" and "or cannot determine". This wording needs to also be added to R1 for completeness. In addition, the wording in the VRFs and VSLs needs to be adjusted to accommodate those events where the cause of the interrupting device operation has not yet been determined.
Yes
The concept of the Application Guideline (AG) is an excellent tool to retain the thought process behind the development of the standard. Use of an AG in this and future standards will help greatly with the understanding, application, and consistency of the standards. Generally, the applications are sufficient for the purpose. Specific comments for clarification include: In "Unnecessary Trip – Other Than Fault", in the paragraph after Example 6d, the "on-site" maintenance activities section needs more clarity. Is the intent of that paragraph trying to say, if the BES Protection System equipment clearly misoperated and personnel had nothing to do with it, then it's a PRC-004 misoperation. If the BES Protection System equipment appeared to misoperate, but it's clear that personnel had something to do with that operation, it's not a PRC-004 misoperation? For a Communication System, does the "on-site" activities exemption apply to anywhere along the communication path were personnel caused what would otherwise look to be a BES Protection System misoperation?
This draft is a significant improvement over the last draft, specifically because of the addition of the "Composite Protection System". We also endorse the use of the rationale boxes within the standard; they lend additional clarity to the requirements of the standard. However, consistent with our comments above, the standard is too prescriptive. For example, there is far too much emphasis on documenting dates. Additionally, most of the VSL's should be eliminated and labeled "N/A", e.g., on R3, does 30 calendar days really matter? Lower VSL should be up to 60 days late, Moderate is N/A, High is N/A, Severe is more than 60 days late which equals failed to identify. ComEd also disagrees with the VSL tables because they disproportionately propose to punish a larger utility with more operations (and misoperations). There also needs to be a distinction between analyzing automatic operations for misoperations but failing to identify a misoperation in, as an example, 1 out of 100 operations verses taking no effort to identify any misoperations. For these reasons we think the current revision to PRC-004-3 is overly prescriptive and complicated. Suggest that the SDT should evaluate simplifying the Standard to the basic

purpose which is to "identify and correct the causes of Misoperation of Protection Systems for BES elements" without introducing hard timelines, overly prescriptive communication requirements, and documentation of the level of corrective actions performed. Guidelines and Technical Basis: (1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. Can the drafting team provide an example for generator protection similar to the one provided for the transmission line protection? (2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation. If the generator is tripped by another relay say out of step, should it still be called misoperations?
Group
FirstEnergy Corp
Richard Hoag
No
Composite Protection System as a new definition is unclear within the context of a Generating Unit as a BES Asset. Protection System, by definition, is already a composite of the five identified components, as applicable. We do not understand the intent of adding the word Composite, or how it changes the current definition of a Protection System for a Generating Unit.
No
R1 and R2 refer to identification and notification "… within 120 calendar days of the BES interrupting device operation …". Currently, submittals to the Regional Entity are due 60 days following the end of a quarter, which could conceivably place it up to 150 days following an event. Besides having to move up the review of Protection System operations, what Evidence will be required to prove the 120 day identification and notification?
No
Does NERC intend to be prescriptive with respect to a template for a Corrective Action Plan, or will the Regional Entities accept whatever format and tracking documentation is provided by the Registered Entities, even though they may be varied among the Entities? The measures identified in M6 seem as though they could be subject to interpretation by an Auditor.
No
None of the Requirements address notifying the Regional Entity on a periodic basis, as is done now (quarterly for RFC). Is it going to be up to the Regional Entity to identify: a. Whether periodic data submittals will be required? b. If so, the periodicity and the template / format for those data submittals?
For FirstEnergy, the "BES interrupting device" (GCB or Generator Circuit Breaker) is typically owned by the TO, due to the location of the POI (Point of Interconnection). However, the Protection System devices which operate the GCBs are owned by the GO. Regardless the

ownership, the GO certainly knows when the “BES interrupting device” (GCB) operates. It appears that a significant emphasis of this revision is to ensure the owner of the BES interrupting device and the owner of the Protection System devices which operate the BES interrupting device are communicating and collaborating in the evaluation. It would seem that the detailed effort to ensure this provides more confusion than clarification for the GO.
Individual
Michael Falvo
Independent Electricity System Operator
No
We do not see the need to create a defined term “Composite Protection System”. By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. In the comment report, it is indicated that 4 commenters representing about 24 individuals requesting clarification of the term “composite Protection System”. This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing a new term which is redundant. We suggest to remove this defined term.
Yes
Yes
a. Applicability Section – Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs similar function when initiated by voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. b. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. “that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met”. Suggest M1 be revised to provide the performance target. c. Measure M2: Similar comment as for M1, above. The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. d. Measure M3: Similar comment as for M1, above. The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. e. Measure M4: Similar comment as for M3, above. The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after

the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. f. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. g. VSL for R3: Second condition under SEVERE - similar comment as for VSL for R1, above.
Individual
Brett Holland
Kansas City Power & Light
Yes
Yes
No
The inclusion of the following phrase is ambiguous. "….. shall perform investigative actions to determine the cause of the misoperation at least once every two full calendar quarters after the misoperation was first identified, until one of the following completes the investigation: The identification of the cause of the misoperation; or A declaration that no cause was identified." I would remove "at least once every two full calendar quarters after the misoperation was first identified." If the drafting team wants to set a time limit on the investigation, then state a not-to-exceed time period. A declaration should be available once an entity has completed all of its diagnostic tests, even if the declaration comes in the first calendar quarter after the misoperation. During the NERC webinar, one of the drafting team members indicated that the declaration could be made at any time, but I can envision a Compliance Enforcement Authority reading the language of R4 and asking why you didn't fulfill the requirement to test in the second full calendar quarter.
Yes
Group
Florida Power & Light
Mike O'Neil

Yes
No comments on the modified “Composite Protection System” definition. However, confusion may result in trying to determine whether an item fits into Misoperation Category 1 “Failure to Trip-During Fault” or into the Category 3 “Slow Trip-During Fault” definition. In both cases, the fault is likely be isolated by remote backup protection schemes. Consider combining Categories 1 and 3. Also, regarding Category 6 “Unnecessary Trip-Other that Fault,” the included wording is somewhat confusing. Consider revising to: “Spurious operation of a protection system in the absence of a fault condition on the power system it is designed to protect.”
Yes
Yes
Yes
The examples are an excellent idea. It would also be advantageous and practical to include supporting information on the scope of Misoperation reporting. Example to consider adding: The boundary of Misoperation reporting extends from protective relay input devices to circuit breaker trip coil(s). More examples should be provided in relation to Power Generation events.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (“PPL”): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: The definition for ‘Slow Trips’ has been improved in the current draft of PRC-004-3, but still requires some revision. The first means by which slow tripping can be manifested, instability, is believed to pertain only to Transmission Systems. The second effect of slow tripping, bringing backup relays into play, does not pertain to generation plants. That is, opening the breaker via a backup relay of a generation plant means not that the primary device acted slowly, but that it did not function at all. This would be a Failure-to-Trip type of Misoperation of the primary relay. We understand that variation-of-tripping is an issue of great importance for Transmission Owners (TOs), but it does not apply for generation plants (such as in the case of high speed tripping to limit system instability). Generator Owners (GOs) additionally do not necessarily have the installed equipment needed to analyze trip speed. Generation plants are not

presently required to have high-speed disturbance monitoring equipment, and many plants still have electromechanical relays (i.e. no oscillograph function). Also, GOs often lack the design-level protection relay staff necessary to perform the activities described on pp. 23-24 of the Application Guidelines.
No
The expression, “identify whether its Protection System component(s) caused a Misoperation when,” in R1 should be changed to, “identify whether (a) its Protection System component(s) caused a Misoperation, (b) functioned correctly or (c) a Misoperation cannot be ruled-out, when.” NERC acknowledges in R4 that many months or even more than a year may be needed to authoritatively classify a relay operation, and this possibility is noted also in R2.2, but R1 requires passing Misoperation-vs.-no Misoperation determination within 120 days. It was stated in the 2/20/2014 Protection Systems Misoperation Webinar that such situations should be addressed by initially assuming a Misoperation, and later ask that the coding be changed if this proves not to be the case. The PPL NERC Registered Affiliates submit (per the guidelines issued by RFC) that in the absence of evidence, a Misoperation should not be assumed.
No
The expression, “or that decided a Misoperation cannot be ruled-out,” should be added in R4 after, “has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3,” per the rationale in our comment above for R1. The outcomes listed under R4 should be expanded as shown below; since, if there are Misoperations for which no cause can ever be identified, there can also be possible-Misoperations for which a yes-or-no determination can never be made. • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven
No
PPL NERC Registered Affiliates comments above for the Slow Trip portion of the Applications Guidelines. A statement should be added, “A Misoperation should not be assumed when the cause of a relay operation cannot be authoritatively established,” (reference response to question #3) The discussion of reverse power relays on pg. 26 would be clearer if it included some of the topics and points made in the 2/20/2014 Protection Systems Misoperations Webinar. We propose stating that “The control-vs.-protective demarcation of reverse power relays is based on the operation at hand and not programming”. Failure of a reverse power relay to open the breaker at the established time after commencement of motoring is not a Misoperation if using the relay to trip a unit as part of a normal stop sequence. The same failure would be a Misoperation if some unintended event caused the unit to import power. The statement on pg. 27, “The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred,” should be amended per our comments above for R4. That is, NERC has stated in R4 that determining the cause of a relay operation may take a very long time, and a Misoperation yes-or-no decision may not be possible if the cause for the

trip is not known. Correction is also needed for the flowchart on pg. 35. “A known or possible Misoperation,” should be substituted for, “the Misoperation,” at the top of pg. 29, and elsewhere that this expression is used, because undetermined cause for tripping can make a Misoperation yes-or-no decision impossible. The statement on p.29, “certain planned investigative actions may require months to schedule and complete,” should be changed to, “certain planned investigative actions may require months or even years to schedule and complete,” in recognition that generation units are intended to operate for years between planned outages and frequently must be returned to service as soon as possible in the event of a forced outage. The following statement should be added at the end of the same paragraph, “Taking equipment out of service for the sake of furthering the investigation is not required, and forced outages need not be prolonged for troubleshooting. However, planned outages should include any testing or other actions for which downtime is necessary.” The discussion on pg. 30 should include the point that a CAP must be developed within 60 days, but implementing the CAP may take much longer if requiring a downtime opportunity. An example should be included for multiple CAPs under the circumstance of extended troubleshooting, (e.g. taking action for the apparent cause of a Misoperation), developing a new theory and taking different action when the event occurs again several months later and making a final and successful corrective action when the problem occurs a third time.
The expression, “the Misoperation,” in R5 should be changed to, “a determined Misoperation,” in recognition of the fact that some events can be classified only after full investigation, as described above.
Group
Duke Energy
Michael Lowman
No
(1) Duke Energy suggests rewording Slow Trip – Other Than Fault as follows: “A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed operation for a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.” By replacing “clearing of a non-Fault” with “operation for a non-Fault”, we feel this better describes the intent of a slow trip that is not a fault.
Yes
Yes
Yes

Individual
Karen Webb
City of Tallahassee
Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
Individual
Bill Fowler
City of Tallahassee
Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
None
Individual
Scott Langston
City of Tallahassee

Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
No
The Extenuating Circumstances process, as outlined on page 32 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the RAI project, Oncor recommends the evaluation of an Extenuating Circumstance be removed from the back end Enforcement phase and up to the Compliance Monitoring phase where the evaluation is done within a risk and controls framework. Furthermore, Oncor recommends the Registered Entity be allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity.
Individual
David Jendras
Ameren
Yes

Yes
(1) Ameren adopts all the SERC PCS comments by reference. (2) A primary reason for our negative ballot on this draft 4 is the proposed clarification (included with SERC PCS comments) to allow a System Protection group of one company's TO, GO, and DP to document R2 and R3 notifications within its database or PRC-004 software, rather than exchange emails or Faxes.
Yes
No
(1) We request the drafting team add another example to clarify the paragraph on page 26, following Example 8b, which includes "…however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." (a) Units in our GO's fleet shut down thousands of times each year, in our opinion Example 8a are applicable. Does the SDT intend to include these as correct operations if indeed the same reverse power relay also provides anti-motoring protection? (b) Our protection scheme in some cases will have separate Device 32 elements, with one short and one longer timer; does the SDT intend in these cases that only trips by the longer timer are within PRC-004 scope? GO will need to know as either of these differ from our understanding of NERC SPCS / RAPA guidance for reporting of total operations under the presently applicable PRC-004-2a. (c) Based on the number of reverse power questions on your 2/20/2014 Webinar, it appears to us that many GO's are unclear on your intent. [Generator reverse power reporting clarity is another primary reason for our negative ballot.] (2) At the end of Example R4a on page 29, please add "Each of 3/24, 4/10, 5/27, and 8/29 actions are valid investigative actions." If the SDT intends otherwise, please state which ones are valid.
(1) Delete from R1 1.1 "or by manual intervention in response to a Protection System failure to operate;" and remove from Rationale for R1, and Process Flow Chart. This is an extremely rare occurrence not warranting special inclusion in the requirements. In our view, manual intervention is already included in that Failure to Trip is a Misoperations and a BES interrupting device did operate, albeit manually. It is acceptable to retain some mention or explanation of it in the Application Guidance to keep it from falling out of the consciousness. Unnecessary Trip – During Fault on page 24 already points out the correct remote clearing that would occur for a Fault. [Unwarranted inclusion of 'manual intervention' in a Requirement is another primary reason for our negative ballot.] (2) Please add "Note: Historically, the cause of about of 10% NERC-wide Misoperations have an unknown cause" at the end declaration paragraph (2nd last paragraph) on page 29. (3) On page 31, please add "For completion of the CAPs in examples R5a through R5d see examples R6a through R6d on pages 33 and 34." (4) We understand R1 to apply to the aggregate set of BES interrupting device operations associated with the same BES event (e.g., fault, abnormal condition, etc.) For example, under present NERC SPSC guidance the entity count all trips in the automatic reclose cycle and reports them as a single event. (5) The NERC PSMTF Final Report recommended grouping all like events involving the same Protection System within a 24

hour period, recognizing that the response time limitations to altering the Protection System. SERC PCS advocated the 24 hour grouping in our comments to NERC on the Section 1600 Data Reporting draft. The resulting metrics more clearly indicate dominant causes, rather than being distorted by repetitive like events on the same Element and Protection System. (6) If the SDT intends that each and every BES interrupting device operations be separately tracked, the TO, GO, and DP certainly need to know this. Although every breaker operation is almost always available within the SCADA log attached in our PRC-004 software database, we group them into a single event record in accordance with applicable NERC guidance. We are concerned that if R1 intends we have a separate event record for each breaker operation, the administrative overhead is unwarranted and burdensome.
Individual
John Seelke
Public Service Enterprise Group
No
We agree with the definition of Composite Protection System, but we believe that the categories definition of Misoperation could be improved. The standard does not address situations where one cannot determine whether the Protection System operated correctly or whether a Misoperation occurred. • Without evidence of a Fault associated with a trip, it is possible that Normal Clearing occurred, although there may be no evidence to support or reject that conclusion. • Without evidence of a Fault associated with a trip, it is also possible that a category 5 (Unnecessary Trip – During Fault) or category 6 (Unnecessary Trip – Other Than Fault) Misoperation occurred; however, there may be no evidence to support or reject either reporting category. In order to address a situation when the operation of a Protection System cannot be determined to be a correct operation or a Misoperation, we believe a seventh Misoperation category should be considered: “Unclassified Trip: Any trip that (a) cannot be confirmed as the correct operation of the Protection System and (b) for which the evidence is not sufficient to place the trip into another Misoperation category.” This will cause all such trips to be consistently investigated as Misoperations. We understand that many of these Misoperations may result in an undetermined cause.
Yes
No
In R4, we find the phrase “two calendar quarters” unclear since it is referenced from the date when the Misoperation was identified. For simplicity, that phrase should be replaced with “180 days.” Also, there may be a need to extend the time. For example, if an investigation required removing a transmission line from service, one may not be able to obtain a clearance to do so within 180 days, so an investigation action could not be performed, resulting is a violation of R4. Therefore, the 180 day time frame should be allowed to be extended for good cause if the owner documents the cause of an extension. Our recommendation is to replace R4 with this language: “Each Transmission Owner,

Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every 180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause), until one of the following completes the investigation:" Finally, in the "Rationale" text box, the phrase "(120 calendar days)" should be stricken since it does not apply to R3. If notice per R2 is given on day 120, the entity under R3 has 60 day time period, while if notice is given on day 1, it has a 119 day time period.
No
The Application Guide is unclear as to the reporting of reverse power relays. A reverse power relay is typically used to remove a generator from service (a control function) AND to prevent generator motoring (a protection function). The two are not separable. On p. 26, example 8a removes the operation of a generator's reverse power relay to open a breaker during routine shutdown from being subject to the standard because it is performing a control function, while the guideline then states "; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." If the reverse power relay failed to open the generator's breaker during shutdown, the generator would motor and the breaker would need to be opened by manual intervention. As the SDT may know, reverse power relays have a documented "blind spot" that causes them to fail to operate during low power factor operation of the generator. (We can provide such documentation if desired). For this reason, generator operators normally have procedures with a step that states that the operator is to manually open the generator output breaker if generator the breaker does not open after a predetermined time period. If this occurred, would the failure of the reverse power relay be reported as a Misoperation? Finally, per the NERC document "Questions and Answers about Consistent Protection System Misoperation Reporting" dated February 5, 2013, reporting a reverse power relay Misoperation and not reporting a successful operation is inconsistent with the principle stated in paragraph #1 that "if an operation would not count as a misoperation, it should not be included as an operation." Therefore, to avoid further confusion, we recommend that reverse power relays used for equipment shutdown be explicitly eliminated from the scope of this standard.
There is no requirement in the standard for the cause of a Misoperation to be determined by the appropriate Protection System owner. Neither R1 nor R3 obligates the owner to attempt to determine the cause of a Misoperation. We note that R4 presumes the owner could not "determine the cause(s) of a Misoperation in accordance with R1 and R3" when those requirements contain no such obligation. R5 and R6 apply to an owner that has determined the cause(s) of a Misoperation. Therefore, we recommend that R1 and R3 be modified as follows with the following additional capitalized language: "…. shall identify whether its Protection System component(s) caused a Misoperation OR NOT, AND IF SUCH A MISOPERATION OCCURRED, SHALL DETERMINE, IF POSSIBLE, THE CAUSE(S) OF SUCH MISOPERATION. " As R1 and R2 are written, one could interpret the language as requiring

ALL interruption device operations be evaluated. However, this is not the intent based upon the draft RSAW that's posted. It states that the evidence required in R1 is "A list of BES interrupting device operations within audit period meeting the criteria of Requirement R1 Parts 1.1 through 1.3." Therefore, we recommend that R1 and R2 be changed so that it is clear that the only interruption device operations that need to be examined are those that are the unexpected. Expected operations for, as an example, switching would be eliminated from any requirement to review the interrupting device operation. This would greatly simplify the data required to demonstrate compliance. We offer the following additional capitalized language in R1 and R2: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated UNEXPECTEDLY shall,…."
Individual
Matthew Wykstra
Consumers Energy Company
Yes
Yes
Yes
No
Generally I agree with the proposed new definition of a Misoperation, but have one hypothetical circumstance where it might be unclear and could perhaps benefit from another example in the guidelines section. Under the category "Unnecessary Trip – Other Than Fault," the guidelines state that an operation that was initiated directly by on-site maintenance…is not a Misoperation. Are there circumstances where on-site maintenance could indirectly cause a Misoperation? We had a situation where a technician was conducting testing on a breaker failure (BF) relay, and accidently initiated the wrong BF relay in an adjacent panel that was still in service and not part of the testing plan for the day, resulting in tripping of the BES bus. Our initial thoughts were that the BF relay should have issued a 'retrip' function to its corresponding breaker after being initiated, thereby only tripping the one breaker instead of the entire bus. Investigation showed the relay was indeed designed to trip the bus and acted properly. BUT if the relay HAD operated improperly after being inadvertently initiated by on-site personnel, would that be a Misoperation? Does the presence alone of on-site personnel create an exemption in all cases? If that is the case, I think it should be explicitly stated, or another example added to clarify technician-induced operations.
Individual
PHAN, Si Truc

TransEnergie Hydro-Quebec
Yes
Yes
Yes
Yes
An addition « Field» can be added to improve metric analysis of microprocessor relays malfunction since these are the type of relays that will be installed in the future by every entities. As the number of microprocessor continue to grow, the more frequent will a Misoperation be caused by these type of relays, therefore this added field would greatly improve metric analysis. For example, the Field Value for a microprocessor relay malfunction could include the following: Setting Error – Incorrect Numerical Input Specified Setting Error – Incorrect User-Programmed Custom Logic Incorrect Design – Incorrect User Application Incorrect Design – Wiring Firmware Version Mismatch by User Others
Individual
Bill Temple
Northeast Utilities
Yes
Yes
No
The term “investigative action(s)” used in Requirement 4 is somewhat ambiguous even given the examples cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. Can simply confirming an outage schedule be enough of an investigative action to satisfy all compliance auditors as suggested in the Application Guidelines?
Yes
Individual
Chris Mattson
Tacoma Power

No
In the definition of Misoperation, Unnecessary Trip – Other Than Fault, change "…caused by…" to "…related to…" In the definition of Misoperation, there may be some ambiguity/overlap in determining if some Misoperations are due to a Slow Trip or an Unnecessary Trip when Protection Systems are found not to have been adequately coordinated. It is suggested that something like the following change be made to Slow Trip – During Fault and Slow Trip – Other Than Fault: Change "…or resulted in the operation of any other Composite Protection System…" to something like "…or a Protection System component failure resulted in the operation of any other Composite Protection System…" Inadequately coordinated relay settings would then more clearly fall under either Unnecessary Trip – During Fault or Unnecessary Trip – Other Than Fault. The only other remedy would be to categorize the Misoperation based upon the corrective action taken. (It should be noted that this ambiguity/overlap is only an issue if Misoperations must later be coded during a NERC data request.) In the definition of Misoperation, Slow Trip – Other Than Fault, consider removing the reference to "…voltage or dynamic instability…" It seems that these issues may be more related to Fault conditions.
Yes
Yes
No
On page 24 of the redlined Application Guidelines, remove the following verbiage: "This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally," This portion does not add value and seems to have a conflicting emphasis with the reminder of the paragraph. Regarding Example 4 in the Application Guidelines, Slow Trip – Other Than Fault, equipment damage is not explicitly identified in the definition of a Misoperation. Either the definition should be revised to clearly identify equipment damage or another example should be used that better fits the proposed definition.
Since Protection System operations that are related to (or caused by, if this verbiage is retained) on-site maintenance, testing, inspection, construction, or commissioning activities are by definition not Misoperations, is it necessary under Requirement R1 to document that the entity identified "whether its Protection System component(s) caused a Misoperation" for these cases of Protection System operations? BES interrupting devices may be operated many times during on-site activities from a Protection System, or part of a Protection System, and it would be very burdensome to document actions taken surrounding this activity for purposes of compliance with PRC-004-3 Requirement R1. Consideration should be given to an additional part under Requirement R1 such as the following: "The BES interrupting device operation was not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities." Regarding the Severe VSL for Requirement R3, change "…whether or not a Misoperation

its…" to "…whether or not a Misoperation of its…" (This also needs to be updated in the VRF/VSL Justification.) Regarding the Moderate VSL for Requirement R5, change the two instances of "…calendar days first…" to "…calendar days of first…" (This also needs to be updated in the VRF/VSL Justification.) On page 32 of the redlined VRF/VSL Justification, in the FERC VRF G3 Discussion, change references to 'VSL' or 'VSLs' to references to 'VRF' or 'VRFs' respectively. On page 39 of the redlined VRF/VSL Justification, in the discussion of FERC VSL G1, change "…being based the…" to "…being based on the…" On page 2 of the redlined Mapping Document, in the Comments column, change "…a review upon a Bulk Electric System (BES) interrupting device operation…" to something like "…a review upon a Bulk Electric System (BES) interrupting device operation initiated by a Protection System and not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities…" Explicitly reviewing and (more to the point) documenting each BES interrupting device operation is overly burdensome, as this would include control operations, including those associated with switching, as well as operations caused during on-site activities. On pages 4 and 19 of the redlined Mapping Document, in the Comments column, change "…a reverse power relay operated to remove a generating unit from service…" to something like "…a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection…" Whether it is for a protective or control function, the reverse power relay will still remove the generating unit from service; the distinction is why the generating unit is being removed from service. On page 5 of the redlined Mapping Document, in the Comments column, change "…underfrequency load shedding (UFLS)…" to "…underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements…" The Applicability does not include UFLS that trips non-BES Elements (e.g., medium voltage distribution feeders). On page 21 of the redlined Mapping Document, in the Comments column, change "…until is…" to "…until it…"
Group
Dominion
Mike Garton
Yes
No
The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date.
Yes
No

a). During the webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples to include: 1. A gas turbine generator has a single reverse power relay which is used to trip the generator breaker during a normal controlled shutdown. This function is considered a control function and not counted as an operation or a Misoperation. 2. The reverse power relay (mentioned in example 1) does not operate to trip the generator breaker and the unit continues to motor until the operator intervenes and opens the breaker manually. Is this a Misoperation? If so what protection system misoperated? Is this considered a Misoperation due to lack of protection? 3. The gas turbine generator mentioned in example 1 and 2 also has a separate reverse power relay that directly trips the generator lockout relay. Is this function considered part of the Protection System? With the unit operating at normal load, this relay incorrectly trips the unit due to an internal relay problem. Is this a Misoperation? 4. A steam turbine generator has a reverse power relay (sometimes referred to as a Sequential trip relay) used in conjunction with valve position switches to trip the generator following a turbine trip. This function is considered a control function and not counted as an operation or a Misoperation. 5. The reverse power relay mentioned in example 4 (sometimes referred to as an Anti-motoring relay) does not operate during a turbine trip and after thirty seconds a second reverse power relay operates as designed to directly trip the generator lockout. Is this second reverse power relay considered part of the Protection System? If so is this counted as one operation that needs to be evaluated? b). Mechanical type breaker trip examples should be expanded to show that air pressure, gas pressure and pole disagreement trips (and their associated auxiliary relays) are control functions and therefore not part of the protection System and thus not subject to this standard. In addition, gas and oil type fault pressure relays on transformers are excluded from Protection System. The example should clarify whether the transformer auxiliary tripping relays (sometimes referred to as 63X relays) are part of the Protection System. Examples could be extremely helpful here since no examples are included in the definition of Protection System. c). Additional Application Guideline examples are needed and the following are specific examples that should be considered: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of its Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the highside breaker that was closed

to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 5. A 230KV line trips at one terminal via its carrier ground relay during closing of a line switch to re-network the line. There was no fault, but the relay operated during typical phase current imbalance created by the poles of the switch closing at different times. Is this a Misoperation?
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes
No
Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording to allow additional time when a utility endures a natural disaster.
Yes
The Severity Level wording (re CAP development) is too stringent and very confusing. Adding roughly 5 days (from the timeframe stated in the previous draft) is negligible. The current requirement allows 12 months for CAP development, and changing this to 120 days will not, in some cases, give a utility adequate time to investigate/determine actions going forth.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Yes

Yes
Yes
Yes
WECC Extended Implementation Period - The Standard as proposed allows entities in the WECC Region an additional 12-months to comply with the Requirements of PRC-004-3. Seminole requests that entities in all other NERC Regions have the same amount of time to comply. Correlating every Region's effective date to that of WECC would be just, reasonable, and less preferential. Evidence Retention - Bullet 2 under section C.1.2. of the Standard deals with evidence retention. Bullet 2 specifically requires retention of evidence 12 months from the date of "completion of each CAP, evaluation, and declaration." It does not appear that Requirement R5 covers the completion of the CAP; it appears that specific requirement is covered in Requirement R6 and bullet #3 of the evidence retention section. Seminole reasons that the drafting team meant Bullet 2 to state that the retention period is from the date of completion of the "development" of a CAP, not the completion of remedies stated in a CAP. In addition, there are three possible dates for completion of a CAP, evaluation, and declaration. Seminole requests that the drafting team clarify which date, and time period, specific evidence is required.
Individual
Steven Mavis
Southern California Edison Company
No
There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry.
No
There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry.
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; GeorgiaPower Company; Gulf Power Company; Mississippi Power Company; Southern CompanyGeneration; Southern Company Generation and Energy Marketing
Wayne Johnson

Yes
Yes, provided that it is made plain that, for the purposes of reportability, the failure or misoperation of an individual component of the Composite Protection System is not to be considered a reportable Misoperation when the Composite Protection System taken collectively functionally did not misoperate. Without this clarification, it is still confusing to state that the failure (misoperation) of an individual component of a Composite Protection System is not a misoperation. We suggest adding "reportable" to all occurances of the phrase "is not a misoperation" to read "is not a reportable Misoperation" where the phrase occurs in the draft standard (12 occurances). The definition of Misoperation, items 5 and 6 need to have the word Composite inserted between unnecessary and Protection
Yes
If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.
Yes
On page 28 of the clean draft #4, in the first sentence of the R4 section, the words "the entity" appearing after the comma are redundant and are not needed.
Yes
1. The removal from R1 of the qualifier of an operation ‘device operation caused by a Protection System operation’ has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device comes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. The added change of including ‘or by manual intervention in response to a Protection System failure to operate’ additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each TOP and GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. Note: related to above 3 comments: Although the recently posted RSAW mitigates some of these concerns, we feel

the Standard itself should be modified to go back to the concept of ‘BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation’ thus removing the need to include the TOP in the applicability. 3. The various timetables introduced in the Standard result in many compliance milestones to be tracked for minimal if any overall increase in reliability. There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. 4. We also observe that the Standard does not require any closure on a specific event. As noted in R6: implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. Therefore, an acceptable CAP could be ‘we plan on upgrading the protection systems in 15 years which will solve the problem’. Since the neither proposed actions nor timetable may change, no update is required. This seems to contradict the statement in the Rational box for R6 which states: Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion. 5. Related to comment#4 above, which notes that there is no requirement for closure: Recognizing that there has been considerable work by various NERC teams (SPCS, RAPA, and the PSMTF) to implement consistent reporting utilizing the misoperation template and that one of the recommendation was that the Regional entities need to become closely engaged in reviewing submittals and following up on action plans/ corrective actions; we would encourage the SDT to consider revamping the Standard to require the quarterly submittal of misoperation data utilizing the approved template and NERC and the Regions to agree on some standard methodology for Regional review and follow-up if progress is not being made.
Group
ACES Standards Collaborators
Jason Marshall
Yes
The definition of Misoperation is much improved. We thank the drafting team for proposing a definition for Composite Protection System. It adds clarity to the standard.
Yes
(1) While we agree the revisions to these requirements clarify what is required, we feel that R2 meets P81 criteria. First, R2 meets P81 criterion A because the requirement of notifying another owner does little to support reliability. Second, R2 meets P81 criterion B1 because it is clearly administrative, and it meets P81 criterion B4 because it requires reporting to another party. Without significant justification for how this administrative, reporting requirement materially and substantially supports reliability, we cannot support it. We suggest that requirement R2 should be removed and an explanation of the desired reporting would be appropriate in the Application Guidelines. The Application Guidelines on page 28 in the first paragraph acknowledges that “notifying the other owners… may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability.” (2) If Requirement R2 persists, we cannot support a medium VRF

for R2. This requirement simply does not rise to the level of having an “impact on the electric state or capability of the bulk electric system” which is what is required to meet the Medium VRF criteria. The requirement is an administrative requirement and does not have any impact on the electric state or capability. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the applicability section. By definition, the Distribution Provider cannot own a “BES interrupting device” since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. If they are not, then NERC/regional entity has made a determination per Note 1 in the statement of compliance registry criteria that the BES interrupting device does not have a material impact on the reliability of the bulk electric system and has not registered them. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the requirement to apply to the Distribution Provider. (4) Requirement R3 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the responsible entity “to identify whether its Protection System component(s) caused a Misoperation.” If a responsible entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown.
No
(1) This requirement should be modified to simply state that the applicable entity is required to identify the cause of the Misoperation or document that a cause could not be found. It is too prescriptive that an applicable entity must identify investigative actions each successive two calendar quarters. This makes the requirement inflexible and needs to be simplified. Consider an example where an applicable entity that should be performing more investigative actions every two successive calendar quarters can be compliant by simply identifying one and an applicable entity in a unique situation that cannot perform even a single investigative action in the two successive calendar quarters due to extenuating circumstances would be in technical non-compliance. (2) This requirement incorrectly implies that R1 and R3 require the applicable entity to identify the cause of the Misoperation. They do not. Rather, R1 and R3 simply require the applicable entity to identify Misoperations. Thus, R4 should be modified to simply require identification of the cause of the Misoperation subject to reasonable investigative actives or declaration that the cause could not be identified after completing reasonable investigative actions.
Yes

The examples in the Application Guidelines are improved and provide additional clarity.
(1) We are concerned that Part 1.1 may cause an auditor to request an inventory of all BES interrupting device operations. From that list, then the applicable entity would be required to identify which BES interrupting device operations were cause by Protection System actuation and which were operator interventions. Then, the applicable entity may have to prove each BES interrupting device operation initiated by an operator was not necessitated by a Protection System Misoperation. Also, the applicable entity would have to show for each BES interrupting device operation caused by Protection System actuation was evaluated for Protection System Misoperation. While we understand that an applicable entity will have to show it evaluated each BES interrupting device operation caused by a Protection System operation, we do not believe they should be required to identify those operations caused by other means such as a manual operation by the operator. To identify cases where manual intervention was necessary due to a Protection System misoperation, the applicable entity should be able to rely on its operator notifying the protection systems department that such actions were necessary. In other words, Part 1.1 should be evaluated based on this exception with the auditor only requesting the applicable entity to identify the instances where manual intervention was necessary. An explanation in the Application Guidelines for what is required here would be helpful. (2) Requirement R1 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the entity “to identify whether its Protection System component(s) caused a Misoperation.” If an entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the requirement. By definition, the Distribution Provider cannot own a “BES interrupting device” since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the Distribution Provider to apply. (4) For the second severe VSL of R3, “a Misoperation its Protection System” should be “a Misoperation in its Protection System.” The “in” is missing. (5) We disagree with the VRFs for R2. It is an administrative requirement and should not even be a requirement since it meets P81 criteria. However, if the requirement persists, the VRF should be no higher than “Low” since it is administrative. (6) Thank you for the opportunity to comment.
Group

Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the response to our comments, but, we do not believe our issues from our past comments have been resolved. Regarding “Slow Trip”: FMPA agrees in concept with providing the ability to apply engineering judgment regarding what tripping “slower than required” may mean but believes there is too much ambiguity. We agree that “It is impractical to provide a precise tolerance ...”; however, If the standard is kept in this format, we support a clarification on the order of “fast enough to prevent harm to the protected equipment, undesired overtripping, or harm to stability.” FMPA believes “BES interrupting device” should be a defined term because it now drives the majority of the compliance activities associated with the standard. Specifically we believe with the way this device is characterized in the Application Guide is deficient. Devices that do not have “fault current interrupting capability” but have load interrupting capability, are often also used for protection functions in “Other than Fault” scenarios. Also, we note that fuses do not qualify as Protection System components although they meet Application Guide description of “BES interrupting device”. Confusion concerning treatment of fuses and the definition of BES Interrupting Device could lead to unintended consequences, such as a proliferation of use of fuses. FMPA still believes that the remaining definitions – Failure to Trip (During and Other than Fault) and Unnecessary Trip (During and Other than Fault) have similar difficulties to “Slow Trip”, wherein the standard provides the leeway for entities to apply judgment but that same leeway affords no way of supporting such judgment with evidence if an auditor disagrees with the interpretation. FMPA also believes that specifically excluding remote backup devices from the definition of Composite Protection System wrongly places a negative connotation on those typically lower voltage (100 – 161 kV) systems in which remote backup for a relay or breaker failure is “as-designed”. We recognize that under the current format it will be difficult to avoid this issue – however if entities were able to develop their own Protection System Design Philosophy documents with this issue specifically addressed (see response to question 5 for more description of this proposed approach) as the criteria against which performance is measured, this problem goes away.
No
FMPA believes there are still ambiguities regarding the responsibility where to or more entities share ownership of a Protection System. Specifically as R1 relates to R2 the language reads in a way that seems to imply entities are required to wait to provide notification of the ongoing investigation to one another, which we believe is not the intent. Furthermore please clarify; where BES interrupting devices are associated with multiple Composite Protection Systems; Does 1.2 refer to the Composite Protection System which is believed to have operated or to all Composite Protection Systems associated with the BES Interrupting device (which may or may not be owned by the same entity)?
No

FMPA believes it would be beneficial to actually lay out specific failures in the examples. For example, “Slow Trip – During Fault” simply says “A failure of a line’s Composite Protection System to operate as quickly as intended for a line fault is a Misoperation.” This is more or less a restatement of the definition but applied with the additional detail of a specific protected component (the transmission line). Rather, consideration should be paid to an actual way a relay could fail – for example “…a line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay’s negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element…” most of the nuance in the application comes from the way the relay failed. Another example might be a line fault with electromechanical relays wherein the relay output contacts stuck initially, resulting in a delayed clear.
In general, FMPA disagrees with the philosophy of the current standard. Protection system design is too complex, too diverse, and requires too much engineering judgment to be conducive to making all system designs and voltage classes of systems fit into one set of criteria. Many of the comments the PSM SDT has been receiving are evidence to that effect. System Protection is just as much an art as it an engineering science (i.e., “The Art and Science of Protective Relaying”, C. Russel Mason, Wiley, 1956). FMPA supports the intent of the statements that the SDT has laid out which seek to provide the individual entities with the ability to provide engineering judgment, but there is no clear cut way to establish measures and allow entities to demonstrate compliance without a set of specific criteria against which the comparison can be made. Thus, FMPA believes entities should have “Protection System Design Philosophies” for their systems as appropriate, analogous to the FAC-008-3 and the prior FAC-008-1 and 009-1 standards and facility Rating Methodologies. Entities can lay out the characteristics of their systems – what is the “intended operation” for the systems, and what, generically, constitutes the constraints around which that entity develops its Composite Protection Systems. We recognize the tremendous amount of work the PSM SDT has put forth in attempting to reach industry consensus on this document but do not believe any form of document that applies criteria without a corresponding philosophy behind that criteria makes the standard too ambiguous. In recognition of the art of protective relaying, we suggest documenting a protection philosophy and intended operation of systems against which to measure whether a protection system operates as intended or not.
Individual
Alice Ireland
Xcel Energy
No
1) The definition for Composite Protection System could be clearer. For example, are the relays deployed at all ends of a transmission line for the protection of that line considered a part of one Composite Protection System? Does the presence or absence of a

communications-assisted scheme change which relays would comprise the Composite Protection System? 2) The definition of Composite Protection System should be modified to account for all of the elements that may or may not operate to protect an element, excluding breaker failure protection. Breaker Failure protection should be considered its own zone of protection. Suggested change as follows: The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. Breaker failure protection should be considered as protecting its own specific breaker element. 3) We have two issues driving our negative vote. The first issue is that high speed performance requirements for identified Composite Protection Systems are not defined or controlled by a single entity with regional grid performance knowledge, such as Transmission Planning. Without centralized accountability to identify performance requirements for specified systems, settings will be installed according to the PRC-001 coordinated settings implemented by the BA, and TO or GO system owners. These settings have been coordinated with the applicable entities. Transmission Planning is the entity that should be cognizant of settings required to maintain system stability under various fault conditions, and notify TO system owners of these requirements for inclusion in PRC-001 coordination. This coordination needs to be identified, tracked, and proper timelines for implementation identified. 4) The second issue driving our negative vote is the lack of a time requirement tied to when a “previously identified” high-speed performance need has to be implemented. For example, under the Slow Trip – During Fault, the phrase “ …if high-speed performance was previously identified…” has no time horizon to make this an effective requirement. If a high speed, 3 cycle fault clearing requirement was identified by e-mail the previous day, and the device was not reset immediately, and a subsequent event caused the device to operate at 30 cycles, a Misoperation would result. Instead, a process by which requirements are identified by the planner, allowing an defined period for implementation, should be required. This could be accomplished by either adding Transmission Planning as an applicable entity with notification requirements defined in the requirement language, or including the GO/TO/Distribution provider as a partner in this process in another standard, such as PRC-001 or the TPL series. Proposed rewording is as follows : Misoperation: The failure of a Composite Protection System to operate as intended and previously coordinated. Any of the following is a Misoperation: Slow Trip – During Fault – A Composite Protection System operation that is slower than for a Fault condition for which it is designed and coordinated. Delayed clearing of a Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. Slow Trip – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed and coordinated, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. And similar edits to all other fault definitions in the document, removing the “…previously identified…” language.
No

1) There appears to be a potential gap if a Composite Protection System wholly owned by one entity experiences a Failure to Trip, and only interrupting devices wholly owned by another entity operate. 2) Propose wording change for R1 through R3 as follows: “R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Associated Composite Protection System component(s) Misoperated when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”; “R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Associated Composite Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”; and “R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Associated Composite Protection System component(s) caused a Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”
Yes
No
1) The examples for R6 in the Application Guidelines are not clear. In R6a, it states the CAP completed on 6/25/2014, but no action is referenced for this date. In R6b, it states the CAP completed on 10/28/2014 when a proactive only replacement program was established, but in R6c and R6d, the CAP is open until the proactive replacement program is completed. It seems the difference between these two is only semantic. 2) Please clarify if it was the intent of the drafting team to exclude operations like the following example from being classified as a Misoperation: Assume that a fault occurs in a generator stator, due to either a mechanical or design setting issue the 64S does not operate. However, the 87 does operate and trips the unit. We believe this would not be a Misoperation because of the overall performance of the composite protection system.
Definition for Unnecessary Trip – Other Than Fault: The first sentence of this is unclear (triple-negative) without the expanded language in the Application Guidelines section. Consider omitting the clause “…for which it is not designed” to make this more clear. The analysis of a Failure to Trip situation does not appear to be covered here, except to the extent that another interrupting device trips in a different zone to prevent the event from propagating.
Group
Santee Cooper
S. Tom Abrams
Agree
Santee Cooper agrees with the SERC PCS Comments.

Individual
Texas Reliability Entity
Texas Reliability Entity
No
Texas RE is concerned that the revised definition of Misoperation is limited to failure of a Composite Protection System, and that this standard does not require investigation and mitigation of all Protection System operations/failures to operate when they are sub-parts of a Composite Protection System. We submit that any failure to operate as designed should be investigated and mitigated, even if another part of the Composite Protection System covered for the malfunctioning component/system.
No
There are several cases in the ERCOT Region where Company A owns the interrupting device and Company B owns the Protection System. In these cases, subpart 1.2 for R1 and subpart 2.1 for R2 do not apply. The language for Requirements R1 and R2 is written such that all of the subparts (1.1, 1.2, and 1.3 for R1 and 2.1, 2.2, and 2.3 for R2) must apply for the entity to initiate the analysis of the operation or notification. We would suggest modifying the language for R1 and R2 to say that the Requirement applies if one or more of the subparts apply.
No
There should be an end time frame for this requirement. If an entity has not determined if a Misoperation occurred within 120 days of the interrupting device operation, they could conceivably continue to investigate the event for years, as long as they perform an investigative action at least once every 6 months.
(1) For Requirement R5, how does the SDT intend to handle a situation where the CAP involves another registered entity. For example, we've seen several cases where the CAP requires multiple TOs to make setting changes in order to mitigate the cause of the misoperation. In this case, should both TOs involved have their own CAP? The requirement language is not clear. The bullet "Explain in a declaration why corrective actions are beyond the entity's control…" provides no assurance that all the required actions to mitigate the Misoperation are completed in cases where multiple entities are involved in the CAP. (2) Evidence Retention: We recommend changing the evidence retention from 12 months to a minimum of 3 years.
Group
DTE Electric
Kathleen Black
Agree
RFC Protection Subcommittee
Individual

John Brockhan
CenterPoint Energy Houston Electric LLC
No
CenterPoint Energy agrees with the new definition for Composite Protection System and believes it is needed to support consistent misoperations reporting. However, we suggest additional clarifications for the two Slow Trip categories of Misoperation definitions that were revised to address high-speed performance. The second sentence of the two Slow Trip categories of Misoperation definitions states: ‘Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System’. We recommended changing this sentence to state the following: ‘If the Composite Protection System is comprised of two, or more, independent high-speed schemes, delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or if high-speed performance was previously identified as being necessary for coordination with other Composite Protection Systems.’
No
CenterPoint Energy believes a requirement to perform investigative actions to determine the cause of a Misoperation at least once every two full calendar quarters after the Misoperation was first identified will result in repetitious investigative actions and scheduled outages and would provide little benefit. Also, we do not believe a declaration is needed, since assigning a cause code of Unknown / Unexplainable is part of the misoperation analysis process. The Cause Code and an explanation of the exhaustive investigation and tests conducted should be sufficient. Therefore, we recommend Requirement R4 be deleted.
CenterPoint Energy recommends revising the wording of the second bullet of Requirement R5 to account for situations where corrective action would not be practical. CenterPoint Energy suggests the following wording: ‘Explain in a statement why corrective actions are beyond the entity’s control or would not improve BES reliability or may not be practical, and that no further corrective actions will be taken.’
Individual
Roger Dufresne
Hydro-Québec Production
Yes
No

For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system . For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation.
Yes
No
For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system . For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation.
The purpose of the Standard shall be limited only to "Identify and correct the causes of Protection System Misoperations affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC.
Individual
Scott Berry
Indiana Municipal Power Agency
No
We see no alternative other than to install SOE equipment and/or Disturbance Monitoring Equipment and/or Digital Fault Recorders to monitor the Composite Protection System during operations/Misoperations of BES interrupting devices. With the current definition of Misoperation, especially the Slow Trip definitions, it will be crucial to the investigation to have exact Protection System parameters and operation times prior to, during, and immediately following any operation on a BES interrupting device. In short any Protection System element (any device subject to PRC-005) must now be logged, recorded, and archived in order for a Registered Entity to be able to go back and show that their Protection System/Composite Protection System operated as designed and did not contribute to a Misoperation on either their own BES interrupting device and/or an adjacent Registered Entity’s BES interrupting device. This will be a considerable expense for smaller GOP’s and DP’s to install, operate, and maintain the equipment and archive the data and records required to meet the burden of these proposed definitions.
No

It is not clear how an entity is to show that an operation of a BES interrupting device happened fast enough and did not fall into one of the two "Slow Trip" categories of a misoperation.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
We believe that the term “local backup” includes breaker failure relaying, but it appeared at the webinar that the drafting team does not intend for breaker failure relaying to be included in the definition of Composite Protection System. We recommend that “local backup” be removed from the definition or changed to “local backup (excluding breaker failure protection).”
No
We generally agree but we have some concerns about multiple entity ownership of different Protection System components compared to joint ownership of individual components.
Yes
Yes
1. The standard is difficult to interpret regarding jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. An interrupting device and all or part of the Composite Protection System may be owned by a contractually-organized group that is not a registered Functional Entity. This makes it unclear which entity is responsible for initial review and potential notification under Requirement R1. Our belief is that it would be the registered entity that is contractually responsible for operating the interrupting device. 2. It is also unclear whether Requirement R2 includes notice to all the other joint-owners of the Protection System or only to the owners of the Protection System components that are not owned by the joint group. Our belief is that notice should only be given to the owners of the Protection System components that are not owned by the joint group. Our proposal to eliminate the uncertainty is to add a statement to the Applicability that addresses how jointly-owned Facilities are to be handled in the standard any time a TO, GO, or DP has a responsibility.
Group
ReliabilityFirst Protection Subcommittee
Bill Crossland
Yes

Yes
There was some confusion on who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion.
No
The direction included in R4 is awkwardly worded. Consider rewording the following “shall perform investigative action(s)… at least once every two full calendar quarters” AS “shall, on a semi-annual basis, continue to show evidence of investigation…”. However, the examples in the Application Guidelines are clear as to what the SDT is looking for.
Yes
Other than our suggestion from Question 2, our group would like to state that the concept of the Application Guideline is an excellent tool to retain the thought process behind the development of the standard. Its use in this and future standards will help greatly with the understanding, application, and consistency of the standards.
We believe that the rationale boxes within the standard should be retained to lend additional clarity to the requirements of the standard.
Group
SPP Standards Review Group
Robert Rhodes
No
With the introduction of the term Composite Protection System, and especially considering the movement from Composite Protection System to Protection System in Requirements R1 and R2, additional confusion may have been incorporated into the standard than existed previously. If there is a way to eliminate the movement from one term to the other or develop a clearer transition from one to the other, it would be helpful to the industry.
Yes
Yes
No
Our preference would be that during a condition of a high number of outages, such as a hurricane or ice storm, we be allowed to request a formal "state of extenuating circumstances" and extend our deadline from 120 days to 270 days. We object to the proposed process where extenuating circumstances can force a utility into a violation and then rely on a nebulous, subjective review to determine whether penalties will be imposed. See additional comments on the Applications Guides contained in Question 5 below.

Exclusions for SPS and RAS are mentioned in the Rationale Box for Applicability. If these exclusions are not incorporated in the RSAW, which was just recently posted and we have not had a chance to review, then the exclusions should be included in the applicability section of the standard. Typos/grammatical/editorial: In the last line of the 4th paragraph on Page 5 under the Background section, insert ‘be’ between ‘to’ and ‘independent’. Insert ‘of’ in both portions of the Moderate VSL of R5 between ‘days’ and ‘first’. Application Guidelines In the definition of Composite Protection System on page 21, change the ‘a’ in front of ‘Element’ to an ‘an’. In the 1st paragraph under Requirement R1 on Page 27, delete the ‘that’ following ‘identified’ in the next to last line of the paragraph. In Example R2a under Requirement R2 on Page 28, set the phrase ‘or DCB relaying’ off with commas. In the last line of the last paragraph under Requirement R3, insert an ‘as’ between ‘such’ and ‘an’. In the 2nd line of the 1st paragraph under Requirement R4 on Page 28, delete ‘the entity’ following ‘notified,’ in the 2nd line. It would be helpful to include the initiating event in Examples R4b and R4c. Hyphenate ‘in-service’ in the 3rd line of Example R4c on Page 30. In the 1st paragraph under Requirement R5 on Page 30, delete the ‘or’ and place parentheses around CAP in the 2nd line. Reword the 1st line of the 3rd paragraph under Requirement R5 on page 30 to read: ‘The time periods within Requirements R1, R3 and R5 are distinct…’ On Page 31 in the introductory paragraph for Examples R5a, R5b and R5c, insert ‘in the relay’ in the 2nd line of the paragraph following ‘capacitor’. Also, in the examples, rewrite the sentence that states ‘Replace capacitor.’ to say ‘Replace the capacitor.’ We suggest the introductory paragraph for Examples R5g, R5h and R5i on Page 32 be rewritten to state: The following are examples of a declaration why corrective actions would not improve BES reliability.’ In Example R5i on Page 32, spell out POTT. In Examples R6a, R6b and R6c on Pages 33 and 34, change the sentence in the 2nd line of both examples from ‘The failed capacitor…’ to ‘A failed capacitor…’ Delete the semicolon in the 2nd line of the last paragraph on Page 33. To eliminate any possible confusion, change the CAP completion date in Example R6c from 03/09/2015 to 03/01/2015. The example gets messy if the completion date is actually after the scheduled completion date.
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
Yes
1. Recommend that R1.3 be simplified by rewording to indicate that “The BES interrupting device owner identified that its Protection System component(s) caused the Misoperation.” 2. The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the Misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. 3. Please add an explanation in the R2

Application Guidelines for situations in which one group investigates for multiple registered entities. It’s quite common for a single protective relay engineering group to investigate for the TO, GO, and DP that their company owns. We suggest the following note “(Note: In cases where a single group performs an overall investigation for several entities each with some ownership of the Composite Protection System; a single document (or electronic database) is sufficient to meet the R2 and R3 notification requirements for use by both Registered Entities.)” be added to the Rational boxes for R1, R2 and R3 as well as to the Application Guidelines. This reduces the administrative overhead of having to send yourself an email just to prove that R2 and R3 are met. The important action of identifying and correcting Misoperation causes is still done and duly documented. 4. Please augment M2 with ‘databases’ to more clearly allow for a single group investigating on behalf of multiple entities (e.g., GO, TO, DP) to date the notification within their database. For example, CTs on a GO breaker may be part of an adjacent TO switchyard bus protection, so there are two entity owners regarding the Composite Protection System. If owned by the same corporation, one system protection group investigates on behalf of the GO and TO, and act to identify and correct Misoperation causes.
Yes
No
See #3 in question 2 above. The examples in the Application Guidelines are beneficial, the SERC PCS suggests it would be beneficial to add additional examples and add clarity to who is to report the Misoperation. Some examples are added below. During the recent webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples specific to reverse power. Also, trips should be expanded to show that air or gas system breaker trips or pole disagreement trips are not reportable operations. Additional examples are needed and the following are recommended: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of it’s Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the high-side breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application

Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 4 A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting
1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device becomes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. 3. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. 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
Russell Noble
Cowlitz PUD
Yes
Yes
Yes
Yes
Applicability section 4.2.2 includes UFLS only if it trips a BES element. We believe that UFLS inclusion in this standard should only be applicable to those single UFLS elements that can have an adverse impact to the BES. Limiting applicability to UFLS elements which trip a BES

element will not adequately address all UFLS adverse impact elements. For example, some industrial loads must be shed in a carefully planned sequence, and it may not be possible to link the UFLS trip signal to a BES element. Instead, the trip signal is received within the industrial load (plant) whereby a controlled plant shutdown is automatically initiated. This load shedding can exceed 200 MW, and is significant. In such UFLS schemes, the actual process of the load shed within a non-BES plant should not be subject to standard compliance; however, the misoperation of the associated UFLS relay as a single point of failure should be considered as a significant BES support device. Inclusion of UFLS in this Standard may be duplicative of PRC-006-1, requirements R11, R12, and R13. An underfrequency event is generally a system wide event; conversely, the objective of Protection System action is to isolate an event to prevent it from becoming a system wide impact. UFLS elements must work as a coordinated system which can withstand several UFLS element failures, yet successfully stabilize the BES. Since PRC-004-3 addresses discovery of problems after an event, we propose that at best this Standard would assure UFLS element Unnecessary Trip misoperations would be mitigated. The discovery of a UFLS element Failure to Trip which has an adverse impact on the ability of the UFLS system to stabilize the BES as stated above is addressed by PRC-006-1. Notwithstanding the above, we do not see our concerns as requiring a negative ballot.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PCS
Individual
Michael Moltane
ITC
Yes
Yes
ITC Holdings is concerned with the documentation requirements to track communications between the BES interrupting device owner and the protection system owner. An auditor may become more interested in communication dates being more important to them than identifying the cause of the misoperation and implementation of the corrective action plan.
Yes
Yes
Individual

Daniel Duff
Liberty Electric Power LLC
No
The maintenance exclusion should include failure to trip as well as trip. Take for example a deliberate roll of a lock out relay as a unit comes offline to test the system. Under the definition if the test caused an early trip it would not be an misoperation. But it is unclear if a failure to trip during the test would be a misoperation.
Yes
Yes
Yes
Individual
Don Cuevas
Beaches Energy Services
Agree
FMPA - Florida Municipal Power Agency
Individual
Steve Lancaster
Beaches Energy Services
Agree