Name (53 Responses)
Organization (53 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (12 Responses)
Comments (76 Responses)
Question 1 (60 Responses)
Question 1 Comments (64 Responses)
Question 2 (62 Responses)
Question 2 Comments (64 Responses)
Question 3 (48 Responses)
Question 3 Comments (64 Responses)
Question 4 (56 Responses)
Question 4 Comments (64 Responses)
Question 5 (0 Responses)
Question 5 Comments (64 Responses)

Group
PacifiCorp
Ryan Millard
No
PacifiCorp believes that the definition used for a Slow Trip During Fault misoperation on Page 4 should be amended to provide more clarity. The current definition reads as follows: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.” PacifiCorp suggests changing “identified to meet” to “identified as necessary to meet.”
No
In the second draft of PRC-004-3 PacifiCorp commented that the 120-day time limit in R1 is insufficient. PacifiCorp maintains that when two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase of 60 days for each entity to complete their respective activities in sequence. This would increase the total from 120 to 180 in R1.
No
PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a “Lower” and a “Severe” VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional 30 days late should not increase the VSL from “Lower” to “Severe.” A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity’s failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days. PacifiCorp recognizes that the drafting team has made this change for the “Lower” VSL in Draft 3, but the remaining VSLs still reflect the 10 day timeframe. Moreover, in keeping with PacifiCorp’s comment under Question 1, the “Lower” VSL should be amended from 120 calendar days to 180 calendar days to allow each entity enough time to complete their respective activities before incurring a violation of the standard.
No
Individual
Greg Froehling
Rayburn Country Electric Cooperative

No
I suggest using the word “entire” versus “composite” for clarity sake. composite (adj) Merriam Webste of or relating to a very large family entire (adj) Merriam Webster having no element or part left out ELEMENT NERC Glossary Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Yes
Yes
Yes
Prefer the term "entire" to "composite" again for clarity sake since entire seems more intuitive in nature rather than composite which requires some anylitical thought to apply it. Example, a transformers entire protection system is slow to operate. Versus, a transformers composite protection system is slow to operate.
Group
Midwest Reliability Organization NERC Standards Review Forum (NSRF)
Russel Mountjoy
No
The NSRF would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn’t have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips.
No
The NSRF believes there should be exception for Acts of Nature such as tornados, ice storms and other natural disasters with, at minimum, the 120 day rule being waived. In previous comments the SDT agreed with this concern but did not add this exception. A wide spread thunderstom with heavy lightning can set off multiple trips and recloses in a short time. There should be a process to excempt such events. Please verify that reclosing relays are not within scope of this Reliability Standard.
Yes
The NSRF appreciates the addition of the Application Guide at the end of the Standard. The Application Guide will help NERC, the Regional Entities and Registered Entities to move away from a zero defact CMEP process.
For R2, depending on time of year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs for some entities. Also, the first bullet under R2 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies.
Group
Colorado Springs Utilities
Charles Morgan
Yes
No
Please consider clarification of the terms “BES Protection System”, “Protection System”, “BES interrupting device” and “interrupting device” throughout the proposed standard. Specifically in R1.1

the proposed requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. The wording of this requirement infers that the proposed standard is intended to include investigation of non-BES protection systems that cause the operation of a BES interrupting device. While such investigation is sound business practice, it may be outside the intended scope of the standard. An example would be the operation of a load serving transformer (say a 230kv to 13.2 kv unit) differential Protection System that operates both a BES interrupting device (a 230kv circuit breaker) and a non-BES interrupting device (a 13.2kv circuit breaker). The stated purpose of this standard is to “Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems” and is supported by the terminology used in the opening paragraph of the Background statement and the content of the Compliance section. Operation of a load serving facility protection system normally will have no impact on the reliability of the BES unless its failure to operate results in a subsequent operation of a BES bus differential Protection System or BES transmission element Protection System, for example. A similar argument can be offered for operation of protection system on non-BES radial lines and local network that cause operation of a high-side interrupting device which may also be part of a BES Protection System. Based on this line of thinking, it is proposed that the wording of requirement 1.1 be revised to state “Within 120 calendar days of an interrupting device operation in its Facility caused by a BES Protection System operation, identify and review each BES Protection System operation.” The wording of Requirements R1.2 and R3 should also be modified for consistency.
Yes
No
As noted in the response regarding R1. We believe that the specific terms need to be clarified in R3 as well to clarify the intended scope of covered situations.
Individual
John Miller
Georgia Transmission Corp
Yes
6. Unnecessary Trip - Other Than Fault: ...is not intended to operate. An Operation caused by on-site maintenance, testing, inspection, construction or commissioning activities on the designated Protection System are not considered as a Misoperation. alternatively: ...is not intended to operate. Operation of a Protection System that is not the focus of on-site maintenance, testing, inspection, construction or commissioning activity is considered a Misoperation. Suggested to highlight the second sentence in the 4th paragraph for defintition 6 in the Application Guidelines.
Yes
While reporting falls under 1600, should PRC-004 clarify which of the two should file the Misoperation?
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes

No
The Protection System component owner who does not also own the interrupting device may be placed in a non-compliant situation through no fault of their own. Their compliance is contingent upon a timely notification from the owner of the BES interrupting device. If the notification is not made in a timely fashion to allow for investigation the Protection System component owner would be non-compliant for not conducting an investigation and documenting the findings within 120 days. For this situation the BES interrupting device owner should have an abbreviated time frame to notify the Protection System component owner to provide sufficient time to collect the appropriate information and investigate the operation. Conversely, the owner of the Protection System component could be granted more time to investigate (i.e. 120 days from the notification by the BES interrupting device owner). A misoperation investigation if Protection Systems are shared between two or more entities is often a joint effort. The Application Guide clearly defines that “it is expected that both entities will work together to investigate the cause of the operation”, which is desired. This is not clearly defined in R1 and should be clarified. The Application Guide should indicate that this notification should be done as soon as possible.
No
We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
No
The Compliance Section of Standard has “The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.” The word “open” should precede not only investigation, but action plan and CAP for clarity. It should be made to read “open investigation, open action plan, or open CAP even if the BES interrupting device operation occurred prior to the current audit period”. What is an Entity’s compliance obligation for an open investigation or open action plan that occurred prior to regulatory approval of this Standard but in the current audit period of an entity? The new standard establishes specific time limits. If an entity has an operation to investigate the day prior to the compliance obligation date, does the 120 day time limit apply the day the Standard is obligatory? Regarding the Implementation Plan for Requirements R1, R2, R3 and R4: “Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months” (this is the compliance obligation date) “following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.” In this section of the Implementation Plan, what is meant by “new”? Is “new” any operation that occur after the compliance obligation date, or during the window of implementation between regulatory approval and compliance obligation date?
Individual
Alice Ireland
Xcel Energy
No
a. (This is the single issue causing us to vote negative.) Many generating units with legacy electromechanical protective relay based protection systems do not have DME for high-speed recording of relay-operation events. Although the generating circuit breakers may be on the HV side of GSU transformers and may be monitored via the associated substation DME, the initiating signals from protective relays on the generator side of the GSU may not provide an input or trigger signal to the substation DME. As such, there is little or no value in requiring Generator Owners to try to identify and analyze slow trip events when such data to perform the analysis is not required to be available. In particular, we are concerned that examples provided in the Slow to Trip – Other than Fault bullet of the Misoperation definition (undervoltage, over excitation and loss of excitation) point explicitly toward application of this portion of the definition towards Generator Owners. We are concerned how various auditors may judge entirely qualitative evaluations of the adequacy of GO Protection System performance for Slow to Trip – Other than Fault events when DME is not available, nor required, to quantify performance. b. Under "Slow Trip - During Fault", is the phrase “Delayed Fault clearing"

intended to be the same as the Glossary term “Delayed Fault Clearing”? If not, the similarity of the existing usage with the defined term introduces ambiguity and confusion about intent. Suggest rewording the second sentence under "Slow Trip - During Fault" to eliminate this potential confusion. Note that similar confusion between the term “Delayed Clearing” used in TPL Standards and the Glossary term “Delayed Fault Clearing” resulted in the NERC Interpretation Request 2012-INT-02.
Yes
Yes
No
It is important to be able to see the draft RSAW, as it relates to what kind of evidence, if any, would be required to demonstrate accurate assessment of a slow trip. This could be particularly problematic, as not all have DME installed to be able to capture data to be able to measure both the start and stop of the operation.
Individual
Michael Moltane
ITC Holdings
Yes
Yes
Yes
Yes
We have no issues with the guidelines, provided there is clarification that the guidelines are not to be used to support audit data request or findings.
Individual
John Seelke
Public Service Enterprise Group
Yes
No
R1 addresses the situation where a BES interrupting device operation may be the result of the operation of a Protection System operation owned by an entity that does not own the BES interrupting device. As written, the owner of the BES interrupting device has no deadline to notify the owners of other Protection Systems when cannot determine that the Protection System operation was correct (the second bullet in Part 1.1). R1 presently allows 120 calendar days in total for the owner of the BES interrupting device to notify the other Protection System owners and for those other owners to determine if their Protection System operated correctly and if they did not, to document each Misoperation, including a cause if one can be identified. As drafted, the owner of the BES interrupting device could notify the other Protection System owners on the 119th day following the operation of its interrupting device, making it impossible for those other Protection System owners to perform their required analysis by the 120th day. The change identified to Part 1.1 below requires the owner of the BES interrupting device to make a notification to the other Protection System owners within 60 calendar days of the operation of its BES interrupting device if the situation described above occurs. The changes to Part 1.2 below allows either Protection System owner 90 calendar days to document the findings of each Protection System Misoperation that may have occurred, making the total number of days allowed from the date of the operation of the BES interrupting device 150 calendar

days. Only 30 calendar days has been added to the timeline, but this additional 30 days is needed to correct the potential inequity for owners of Protection Systems that do not own the BES interrupting device to complete their analysis. For consistency, 30 calendar days was added to the R3 timeline of 180 days, making it 210 days from the date of the operation of the associated BES interrupting. R2 is unchanged, but is shown for completeness. We have also added a provision in a footnote that allows a Regional Entity to extend deadlines that are referenced to the operation date of a BES interrupting device for instances such as natural disasters. Personnel that might normally evaluate the operation of a Protection System may not be available to do so due to their involvement in restoration efforts. Here is our suggested changes. Additional language is CAPITALIZED. R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 Within [delete "120"] 60 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation AND [FOOTNOTE 1];. • If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation, OR;. • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. FOOTNOTE 1: Such 60 day period and subsequent periods in the standard that have a deadline that references the operation date of a BES interrupting device may be extended by the Regional Entity for instances such as a natural disaster. 1.2 Within the same [delete "120 day period"] 150 CALENDAR DAYS of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified. R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 210 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken.
Did not review.
No
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
No
M1 – DME is not defined. M3 - What was the reason for removing the words at the end 'explaining why no further investigation or actions will be taken' - these words are helpful and should be retained. VSLs – R1 – Severe VSL – the final option in this column seems to suggest that you would need both a failure to notify the other owners AND a failure to provide any investigative information. It doesn't contemplate a situation where an entity may have notified the other owners but failed to provide investigative information.

No
Background - The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". Moreover, the terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above. R2 - the words 'If a cause is identified' after the words 'cause(s) of each Misoperation' would be helpful. The way It reads, R2 is only applicable if a cause is identified and R3 is applicable if a cause if not identified so the Measures for each should be drafted in a way that makes that point clear. R3 – the words ‘caused by a Protection System operation’ should be added after BES interrupting device operation to make the wording consistent with the other requirements. R4 – In reading the rationale for R4, it states that if a cause of a Misoperation is determined when implementing the action plan, you go back to R2 and develop a CAP. This isn’t evident on the face on the wording of the standard and the Rationale will be deleted going forward. R4/M4 – should be consistent with use of ‘and’ or ‘or’ when referring to the CAP and action plan, perhaps best option is to use ‘and/or’. Compliance – 1.1 – Manitoba Hydro has never before seen a reference to the definition of CEA per the NERC Rules of Procedure in this section, it seems unnecessary. Compliance - the phrase BES Protection System is elsewhere referred to as Protection System for Facilities that are part of the BES which seems more accurate and should be consistently used.
Individual
Patrick Brown
Essential Power, LLC
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: -The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. -Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. -The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). -Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own…" by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to …then list the items once.
No
See comments to question 2
Yes
The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks

linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?
Group
Mary Jo Cooper
Mary Jo Cooper
Yes
Yes
No
This Standard allows 120 days for the entity to investigate the operation. We do not feel that this activity warrants a severe violation factor if only 1 operation was investigated 50 days later. We agree that if an activity has a significant impact on the BES than the violation severity level should be higher. In this case, however, immediate action is not required and therefore we disagree with the severe violation penalty suggested by the drafting team. We suggest that the penalty for not investigating an operation timely should only qualify for a moderate VSL given immediate (within 1 hour or 1 day) activity is not required. We feel investigation of all operations and determination and implementation of correction misoperations is important to the long-term reliability of the BES. However, the system should be designed with redundancies to resolve any short-term issues and this Standard, while important, is designed to ensure long-term protection. Furthermore, we are not aware of any company who feels that the violation severity level determines whether they comply or not. Our organization strives to comply with all Standards with no violations, regardless of the violation severity level.
Yes
Group
ISO RTO Council Standards Review Committee
Charles Yeung
Yes
Yes
There is a lack of clarity on which entity is responsible for developing and implementing a CAP. We agree with the revision to Requirement R1, but believe that there needs to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible, expecially in view of the rationale provided in the text box for R1, whose excerpt says: “The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”. We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest to revise the leading part of R2 to: “Each Transmission Owner, Generator Owner, or

Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying….”. The Same revision should apply to R3, as follows: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of of the associated BES interrupting device operation,…..” Further, though not explicitly stated, we assume that the owner of the component that contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.
No
As we noted in our comments in the previous draft, the VSLs should recognize that some relay misoperations place a greater risk/impact on the BES than others.
Yes
Individual
Kayleigh Wilkerson
Lincoln Electric System
MRO NSRF
No
Although supportive of the proposed revisions to the definition of Misoperation, LES is concerned that the phrase “slower than intended” within the definition of a “Slow Trip – During Fault” may lead to unnecessary administrative work in an effort to prove what is considered an acceptable operation time for each Protection System. To avoid requiring entities to develop documentation stating “how fast is fast enough”, recommend modifying the Application Guidelines as follows: (3) …The phrase “slower than intended” means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate. [The intent is not to require documentation of adequate Protection System operation times, but to assure consideration by the owner(s) reviewing each Protection System operation.]
No
LES recommends additional clarification be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
No
ATC believes that the investigation for relay misoperation should be performed by the owner of the initiating relay as opposed to the interrupting device owner for the following reasons: • By definition, “Circuit breaker and other interrupting device mechanisms are not part of a Protection System”. As such, PRC-004 should not require the interrupting device owner to be responsible for R1. • PRC-004 is

based on Protection System operation, not breaker operation. • Bus design can have multiple breakers owned by different entities but the ownership of the initiating relay is clear. • The BES interrupting device owner lacks the information that the protective relay owner has to be able to perform a root cause analysis of a misoperation.
Yes
Group
seattle city light
paul haase
Yes
Yes
Yes
Yes
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the ICP include specifications that the entity identify mitigating factors performed under the CAP that specifically address the Misoperation.
Individual
Jack Stamper
Clark Public Utilities
Agree
Sacremento Municipal Utility District
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Bill Middaugh
Tri-State G&T
Yes
Yes
Yes
The first instance of the abbreviation, DME, is undefined in M1 on page 7. It is defined as Disturbance Monitoring Equipment on page 19 in the Guidelines and Technical Basis section for R1. The definition should be moved to page 7.
No
None

Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
It is not appropriate to make the owner of the interrupting device responsible to investigate Protection System operations. Interrupting devices as such are not components of a Protection System as defined by NERC. Responsibility for this investigation should be solely with the owner of the Protection System initiating the operation, and/or the owner of the Protection System which failed to operate.
No
Since owners of BES Protection Systems will be required by this standard to review all operations, it would be helpful to define the term "Protection System operation", at least as it is used in this standard.
Individual
Joseph DePoorter
Madison Gas and Electric Company
Yes
No
Please see question 5.
No
Under R4 there is confusion when the words "complete" is used. It should be stated (here and in the requirement) that an entity can extend the 180 days to complete if they have supporting documentation, i.e., parts on order, work orders, etc.
: As written in R1.1, if a BES generator's normal shut down cycle is caused by a Protection System operation (a set trip point in the relay) then each shut down would be required to be "identified and reviewed". This is similar to issues that a generator operator has under Project 2011-INT-02 AVR control during start up and shut down. MGE recommends that either a footnote be provided to address the exclusion of normal shut down processes or add another bullet excluding a generators normal shut down processes where the unit's breaker is activated via a set point within the Protection System (i.e., relay). R4 could be viewed as allowing for CAPs to be extended beyond 180 days (the maximum days in the combonation of R1 and R2). If this is the intent of the SDT, then clearly state this within the requirement. As written, an entity could be in violation of the maximum time frame of 180 days by extending the CAP under R4.
Individual
John Bee
Exelon Corporation and it's affiliates
Yes
Yes
Yes
The following changes are suggested: R1 – Add a Lower VSL condition that states, "The responsible entitiy failed to identify and review at least 2% or 2 (whichever is greater) Protection System

operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”. Add a Moderate VSL condition that states, “The responsible entitiy failed to identify and review at leastr 3% or 3 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”. Add a High VSL condition that states, “The responsible entitiy failed to identify and review at least 4% or 4 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”. Modify the 2nd Severe VSL condition with, “The responsible entitiy failed to identify and review at least 5% or 5 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1”. Eliminate the 2nd Lower VSL condition all together because it is redundant with the 1st Severe VSL condition that addresses performing the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 170 days. R2 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R3 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R4 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed.
Yes
Exelon would like additional clarification added to the Application Guide regarding the inclusion of CAP corrective actions for addressing the application of the CAP to other Protection Systems owned by the utility. Specifically, the Guide should address that such a CAP can be considered complete once a program (required to address application of the CAP to other Protection Systems) is developed. Example 2 in the Application Guide exemplifies this notion. Additionally, application of the CAP to other Protection Systems owned by the utility should be considered fulfilled if an existing program (such as Protection System maintenance and testing practices) fulfill the actions necessary to address such a CAP.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
No
We would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn’t have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips. Depending upon the guidance requested in the SPP comments (what will be required to prove that all faults have been analyzed) the time frames may become difficult to maintain especially during storm seasons. Likewise, the 60 days required to develop a corrective action once the cause is determined could become difficult for severe or extreme events. In extreme cases dynamic power flow models may need to be developed and applied to system studies before the CAP can be developed.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Yes
No

Requirement R1 places the responsibility on the BES interrupting device owner to investigate all operations initiated by a Protection System which trips the interrupting device. We vigorously disagree with this assignment of responsibility. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the tripping of the interrupting device, not the owner of the interrupting device. All previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. Therefore, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device. The entity who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO's breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for reviewing and identifying all GO protection initiated trips just because the TO owns the interrupting device. This is totally unreasonable. In a power plant, when a generator unit trips off line due to a plant Protective System operation lockout relays are employed to prevent re-energization of the unit until the cause of the trip can be determined. When this occurs, the investigation of this event should be initiated and pursued solely by the GO (i.e. the owner of the protective system that caused the tripping of the BES interrupting device) and not by the TO, who may happen to own the interrupting device. The GO may request data and information from the TO to assist in their investigation, however, all compliance responsibility for reviewing operations and identifying misoperations should solely rest on the owners of the Protective System(s) that initiated the trip of the BES facility (in this case the GO). In this case, involving the TO solely because they are the owner of the interrupting device places an unwarranted compliance burden on the TO. Although the TO may be aware that the interrupting device opened, they are not is a position to determine if it was opened due to a plant Protective System operation, or was opened due to a manually initiated trip of the unit as it was being taken offline, since the GO, rather than the TO, usually has operational control over these breakers. In order to properly assign compliance responsibility to the appropriate entities, and eliminate the unwarranted compliance obligation on the interrupting device owner, we would suggest re-wording R1 in either one of two ways: OPTION 1 - Preferred: (assign responsibility to each Protection System owner rather than to the interrupting device owner) R1.1 "Within 120 calendar days of the operation of an interrupting device(s) which interrupts a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which is connected to trip the interrupting device(s) shall review the event to determine if their Protection System operation was correct, or a misoperation." With the above language the responsibility is clearly and properly assigned to the owner(s) of the Protective System(s) which initiated the tripping. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. While retaining this approach for shared Protection Systems the remaining Parts of Requirement R1 will also need to be re-worded to remove references to the interrupting device owner. OPTION 2 - Alternate: (replace owner of the interrupting device with owner of the interrupted BES Facility) R1.1 "Within 120 calendar days of the interruption of a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, the Transmission Owner, Generator Owner, and Distribution Provider, who owns the Facility that was interrupted shall identify and review each Protective System operation. If the entity owns both the BES Facility and the Protective System, determine if it was a correct operation, or a Misoperation. If the entity owns the BES Facility but does not own all of the Protective System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protective System component(s) and provide any requested investigative information. The Protective System component owner(s) that was notified by the Facility owner shall determine if there was a correct operation or a Misoperation of their component. 1.2 Within the same 120 day period of the

interruption of a BES Facility caused by a Protective System operation, the owner of the Protective System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.” The above language is consistent with the way TADS and GADS data is entered (i.e. by the Facility Owners). In addition, the Protective System(s) which protect and trip a specific Facility are almost entirely owned by the owners of the Facility. This Option adequately addresses the example raised previously, eliminating the need to involve the TO for generator initiated trips. The only complication arises when dealing with transmission lines terminating between two separate companies. The line terminals at each end may be owned by each respective company but the line itself may be entirely owned by only one company. To overcome this deficiency, this proposed re-write of R1 uses the term “line terminal” in the parenthetical list of BES Facilities. This would make the owners of the Protective Systems on each respective line terminal responsible for the review and analysis of their systems rather than the owner of the line itself.
No
Measure M1 requires evidence “that documents the date and time of each applicable interrupting device operation and indicates when each related Protective System Operation was reviewed.” Based on our comments from Question 2 and proposed re-wording of Requirement R1, Measure M1 should also be revised to require evidence “that documents the date and time that each BES Facility was interrupted due to the operation of a Protection System and the date the Protection System operation was reviewed.”
Yes
On page 18 of the Guidelines and Technical Basis section it states “Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System Operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation.” Furthermore, on page 19 it states “Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation …” Based on the arguments presented in our response to Question 2 we vigorously disagree with this assertion. When a Protective System operates, a means is provided to determine which protective component initiated the trip (i.e., relay targets, lockout relay operations, microprocessor relay event logs, etc.) The owners of these Protective System devices, which initiated the trip of the interruption device, are much better suited to investigate the cause of the Protective System operation than the owners of the interrupting device. In addition, all previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT’s) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. In conclusion, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device.
To avoid confusion, Requirements R2, R3, and R4 should be re-worded to make it clear that they apply only to those entities whose Protective System misoperated and not to the interrupting device owner. The following language is suggested: R2. “Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall within 60 calendar days of identifying the cause of each Misoperation…” R3. “Each Transmission Owner, Generation Owner, or Distribution Provider shall, within 180 calendar days of the interruption of the BES Facility due to a Protective System Misoperation, complete for each Misoperation without an identified cause….” R4. “Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall implement each CAP or action plan, and revise as needed through completion.”
Group
City of Tacoma, Tacoma Public Utilities

Chang Choi
Yes
Is mechanical failure of an interrupting device during a fault a mis-operation? (The interrupting device is not part of the Protection System.) Is inappropriate operation of a relay that operates upon mechanical inputs a mis-operation? For example, what if the relay causes a trip when it should have restrained?
Yes
Yes
No
Comments: Is it the intention of the PSM SDT that this version of the standard would require that all BES interrupting device operations be logged (documented) with a determination of whether the operation was caused by a Protection System? While it appears to be the intent of the draft revised standard that all interrupting device operations be reviewed at some level to determine if a Protection System caused the operation, it is unclear whether explicit documentation of each interrupting device operation must be generated and retained for purposes of compliance with PRC-004-3.
Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own…" by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to …then list the items once.
No
See comments to question 2
Yes

The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?
Individual
NICOLE BUCKMAN
Atlantic City Electric Company
Agree
Pepco Holdings Inc and Affiliates
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
No
See response under Question #5 with specific recommendations to implement Internal Controls.
No
The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
No
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
Midwest ISO
Individual
Thad Ness
American Electric Power
No
AEP recommends removing the reference to "TPL standards" from the "Slow Trip - During Fault" category of the definition. AEP believes the intent of the "TPL standards" reference can be maintained

by capturing all slow trip events that result in clearing more Elements than necessary. AEP's first preference is to reword the category as follows "Slow Trip - During Fault - An Element's composite Protection System operation that, due to the duration of the composite Protection System's operating time, resulted in the clearing of other Elements in addition to the Faulted Element.". AEP's second preference is "Slow Trip - During Fault - A composite Protection System operation for the Faulted Element it was designed to protect which was slower than intended. Delayed Fault Clearing due to the non-operation of an installed high-speed protection scheme is not a Misoperation provided the duration of the composite Protection System's operating time did not result in instability or cascading, and did not result in miscoordination with any other composite Protection Systems." AEP recommends adding to both "Failure to Trip - During Fault" and "Failure to Trip – other than Fault" - "Please see Category 3(4) to determine if the "slow trip" classification applies to the operation."
No
AEP recommends the following modification to 1.1: "Within 120 calendar days of a BES interrupting device operation in its Facility caused by a BES Protection system operation or by manual intervention due to a BES Protection System failure to trip, identify and review each BES Protection System operation and BES Protection System failure to trip." AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs near the end of the 120 day period, and the notified entity does not have sufficient time to determine if their component operated properly or misoperated within the 120 day period. AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs more than 180 days after the BES interrupting device operation. AEP requests that R1 should be modified to clearly indicate whether the term "entity" includes separate Functional Entities within the same Registered Entity. As written, it is unclear if the Transmission Owner function is required to notify the Generator Owner function within the same Registered Entity for compliance with R1.1 Bullet 2 or if the Registered Entity with multiple Functional Entities is treated as a single unit for ownership purposes. R1.2 appears to add little value as a standalone requirement. AEP recommends removing R1.2. and incorporating the requirement to identify a cause within the remaining R1 and R3 wording.
No
AEP recommends adjusting the time requirements specified in the VSL tables for R1, R2 and R3 to extend the timeframe for Moderate and High VSLs to 20 days, and eliminate the time requirement for the Severe VSL. Example: For R1, the Low VSL remains the same, Moderate becomes >150 to 170, High becomes >170 to 190, and Severe only applies when "The responsible entity failed to identify and review… ". Measure M1 repeatedly lists the same evidence examples and AEP suggests simplifying the measure by stating "evidence for R1 may include but is not limited to…." followed by a single list of items. The wording for the R4 VSL references failure to revise a CAP "as needed". This statement is very broad, may be subject to interpretation and should be clarified or removed from the VSL.
No
AEP recommends adding "remote backup relaying is not considered to be part of the composite Protection System" to the end of the description for the composite Protection System in the Application Guidelines. AEP requests that SDT include a clarification of the meaning of "BES interrupting device" within the context of this standard (similar to how "composite Protection System" is addressed). AEP recommends replacing both instances of the word "implementation" with "development" in the second paragraph of page 20 of the clean version of the standard. Otherwise it is implied that there are situations where a CAP must be fully implemented within 180 days. Please include a clarification of the CAP and action plan modification tracking. For example, if a CAP or action plan is modified, is it sufficient to document the modifications, or must the date the modifications were made also be tracked? On page 15 of the clean version of the standard AEP recommends adding "unintentional" before "loss of field" in the first paragraph. On page 15 of the clean version of the standard AEP recommends replacing "shut down" in the second paragraph with "as intended to isolate." AEP recommends adding generation examples of both a normal time delay operation and a misoperation to category 3 of the application guidelines.
In the Rationale for R2 box, a reference is made to R4. This appears to be a typo and should be changed to R3. Since an evaluation is not part of the Corrective Action Plan definition, please make the following modification to the first bullet of R2: " Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and also an evaluation of the Action Items applicability to the entity's Protection Systems at other locations, or.." AEP recommends revising R2, R3, and R4 to

specify that only the owner(s) of the Protection System component(s) that misoperated are responsible for applicable requirements. Measure 2 should be revised to remove the statement “explaining why there is no need to develop a CAP.” This is consistent with Measure 3. Declaration is described elsewhere in the standard. The Standard may read more clearly if the existing R2 and R3 were switched such that the requirement to develop a CAP (R2) came *after* the requirement to identify a cause or develop an action plan (R3) to complete further investigation. The phrase "composite Protection System", which is described in the Application Guidelines section, is not used in the Requirements, Measures, or Compliance sections. AEP requests "Protection System" to be replaced with "composite Protection System" where appropriate throughout the standard.
Group
Dominion
Mike Garton
No
The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
Yes
No
The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
: Suggest the Implementation Plan be modified under the Applicaibility section as indicated below: This standard applies to the following Facilities: Protection Systems for BES Elements. Underfrequency Load Shedding (UFLS) that trips a BES Element This standard does not apply to the following Facilities: The flowing Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) Non-protective functions that may be imbedded within a Protection System Suggest the Mapping Document be modified under the Proposed Language in PRC-004-3 column as indicated below: 4.2.1 Protection Systems for BES Facilities, Facilities needs to be replaced with Elements.
Individual
Anthony Jablonski
ReliabilityFirst
No
The revision to part three of the definition that converted the original parenthetical example into an exclusion by stating it inversely creates a potential loophole. The revised wording would consider correct the slow operation of a Protection System that caused avoidable equipment damage (due to the delayed fault clearing) as long as it did not cause a dynamic stability or coordination issue. The Protection System also needs to coordinate with the damage curves of the equipment within its zone. As the exclusionary sentence stands, it actually uses double negatives. It would be better to restate the sentence positively. A suggested improvement would to replace the second sentence in part three of the definition with the following: Delayed Fault clearing associated with an installed high-speed protection scheme is an example of a Misoperation if high-speed performance is required to meet the dynamic stability performance of the TPL standards or is required to ensure coordination with other Protection Systems.
No
Requirement R1 relies on the operation of an interrupting device and the identification by its owner that a Protection System operated and further that it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard. 1) First, the owner

of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. This partly is because the interrupting device excluding its trip coils and CTs is not part of the Protection System. The owner of the relay that activated the trip or the owner of the associated Disturbance Monitoring Equipment would be in a much better position to evaluate the operation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process. 2) Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it. 3) Finally, the requirement should be rewritten to obligate the owner of its Protection Systems to investigate their performance and to notify joint owners of their findings if they need to take follow up actions. Inserting the interrupting device owner unnecessarily into the process of investigation does not serve a reliability purpose but an administrative one.
Yes
No
Although this draft of the standard is considered a Results-Based Standard it is difficult to see how the requirements are written to achieve a measurable outcome associated with reaching a level of reliability performance, a reduction in reliability risk or a necessary level of competency. This draft standard instead appears to be administrative in nature that is more concerned with creating documentation solely for compliance purposes. The following are specific issues or suggestions: 1) the standard contains extra 120 day and 60 day deadlines that do not provide reliability benefit. Although there is value in investigating Misoperations quickly, it is more important to fix the problem and prevent its reoccurrence. 2) Late identification of Misoperations will be a violation even if they are not particularly significant. Specifically, Misoperations that occur with no Fault present may not be readily apparent. The deadlines in the standard could cause disincentives to fully investigate Protection System performance because it may result in compliance violations. 3) The standard provides no means of ensuring that Misoperations are addressed by CAPs on a timely basis. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause for this type of Misoperation should be either mitigated or the CAP completed in less 12 months. 4) It is suggested that the drafting team embrace a reliability performance based approach that would fit into the results-based philosophy. Specifically, adherence to the standard should be based on achieving or surpassing certain metrics such as Misoperation rate, the percent of causes unidentified (Unknowns/All in a year) and the percentage of open CAPs (Open CAPS/Misoperations in a year). These metrics are meant only as potential examples for measuring performance. By requiring certain levels of performance or continuous improvement in these metrics, then the goal of the standard can be met without the administrative burden of tracking relatively unimportant dates such as when a cause was identified or when a CAP was developed and the storage of large volumes of evidence records.
Individual
Mary Downey
City of Redding
Agree
BANC/SMUD
Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes

Yes
No
Only a request that the application guidelines be maintained with the final version of the standard.
Individual
Bill Fowler
City of Tallahassee
No
Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.
No
There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation.
No
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency and has a couple of additional comments. Since the comment document is not formatted for this purpose, we will submit them here. The standard is titled Protection System Misoperation Identification and Correction, not Operation Identification and Submittal. IMPA does see that an organzation might keep track of operations but to require this action by a standard requirement and then potentially find an enitity in non-compliance is over reaching for this Protection System Misoperation standard. In order to be in compliant with this stadnard, an entity should only be required to perform the action of Protection System Misoperation Identification and Correction which is the standard title. Another problematic area involves the "same 120 day period of a BES interrupting device operation caused by a Protection System operation". What happens if the owner of the Protection System component is notified toward the end of the 120 day period of a BES interrupting device operation (say 119 day) and there is not sufficient time for an investigation by the Protection System owner into the cause of the trip? The Protection System owner should not be found non-compliant for requirement 1.2 if not enough time is given to them to properly investigate the reason for the operation of the Protection System.
Group
Tennessee Valley Authority
Brandy Spraker
No

The proposed Misoperation definition is based on the “Protection System” definition defined in the NERC Glossary of Terms (GoT). However, the NERC GoT does not provide the elements that are considered “Protective System” elements. The actual descriptions of the “Protection System” elements are found in PRC-005-2, 4.2 Faciliities. Recommend this PRC-004-3 revision include a new GoT definition of “Protective System Element” based on PRC-005-2, 4.2, Facilities, or a revision to the NERC GoT to include an abbreviated summary of the PRC-005, 4.2, Facilities in the “Protection System” definition; or include an abbreviated summary of the PRC-005-2, 4.2 Facilities into the PRC-004-3 definition of “Misoperations;” or revise both the NER GoT definition of “Protection System”, and PRC-004-3 definition of “Misoperation” to reference PRC-005, 4.2, Facilities, as the elements that are “Protection System elements.”
No
The changed wording of R1 was an improvement. However, our concern comes from our company enduring a major natural disaster and the aftermath. When recovering from a major event 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 weeks and is not the top priority for a utility that endures such an event. The Standard needs wording to allow additional time when a utility endures a natural disaster.
No
As per Req. 2 - CAP Devlopment is too stringent. Troubleshooting and determining which element could take longer than the time allowed in the VSLs. Under PRC-004-1 a 12 month time period was given to develop and implement a CAP. Recommend a CAP not developed w/in 120 days or a declaration in accordance with Req. R3 (Lower VSL), CAP not developed w/in 120 days or a declaration in accordance with Req. R3 w/in 120 days or CAP declared in accordance with Req. R2 not implemented within 150 days (Medium VSL), CAP not developed w/in 150 days or a declaration in accordance with Req. R3 w/in 150 days or CAP declared in accordance with Req. R2 not implemented w/in 180 days (High VSL), CAP not developed w/in 180 days or a declaration in accordance with Req. R3 w/in 180 days or CAP declared in accordance with Req. R2 not implemented w/in 210 days.
No
The PRC-004-3 requirements’ rationale for each requirement (gray boxes next to each requirement) and the Guidelines and Technical Basis (at the end of the document) are well thought out and contain significant justification and logic for each standard requirement. Recommend either keeping this information attached to the standard or formalizing it into a reference document that will will be easily accessible to the electric power industry. There was no indication in the draft standard as to the repository of this significant information.
Group
Duke Energy
Greg Rowland
No
The revised definition still contains the incorrect reference to TPL standards in “Slow Trip – During Fault”. The TPL standards Category A, B and C do not require Planning to identify every place where high speed protection is required for dynamic stability. If a Category B issue is identified, high speed protection is installed and it is no longer on the Category B list. If a Category C issue is identified, a redundant relay scheme is installed and it is no longer a Category C issue. Therefore, the list of places where “high-speed performance has been identified to meet the dynamic stability performance requirements of the TPL standards” is just a list of where the appropriate corrective action has not yet been implemented and could, in theory, be empty. “Slow Trip – During Fault” should be revised as follows: “A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified as needed by the Planning Authority or the Transmission Operator, or if it is not required to ensure coordination with other Protection Systems.”
Yes

Yes
Yes
See our comment above on Question #1. The following paragraph should be deleted from the accompanying Guidelines and Technical Basis section: “The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability . The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.”
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
No
Agree with the other changes but VSL severity levels are spaced 10 days apart. It should be at least 30 days apart. It is not justifiable to go from Lower to Sever VSL for 22 days of delay (149 days to 171 days). There is no justification for such strict time lines.
No
Individual
Don Jones
Texas Reliability Entity
No
The SDT may want to consider adding loadability as an example under “Failure to Trip – Other Than Fault” and under “Unnecessary Trip – Other Than Fault”. The existing definition of the ‘Slow Trip-During Fault’ needs to include that the delayed fault clearing associated with the installed high-speed performance of the protection system is not required to meet the voltage ride-through capabilities of the generators. Generators should not be tripping off line due to suppressed voltage in the system stemming from the delayed fault clearing. This could create steady state voltage issues. Suggested language: "Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems ***or result in loss of generation due to delayed fault clearing time***." Also, the definition of “Slow Trip – During Fault” refers to stability performance requirements of the TPL Standards, however, the TPL Standards do not cover delayed three-phase fault clearing studies. Delayed three-phase fault clearing can create undesired system conditions.
No
See comments submitted in response to Question 5 below.
Yes
No
The first paragraph of the Guidelines and Technical Basis defines the composite protection system to include the backup protection. This needs to be clearly defined as “local backup” only and not to

include remote backup protection.
We are concerned that the applicability of the Standard limits the misoperation analysis only to BES Element Protection Systems. Under the new BES definition and guidance documents, there will be numerous examples of misoperations on non-BES Element Protection Systems which could have a major impact on the BES when the fault must be cleared by remote backup relays. Example: Consider a 50MVA generator connected to a substation via a radial line. Under the new BES guidance, the generator is part of the BES while the interconnecting radial line would not be part of the BES under exclusion E1(b). If a fault occurs on the non-BES radial line and the Protection System fails to trip, the fault must then be cleared by either local or remote backup relays at the interconnecting substation(s). Under this scenario with the current proposed PRC-004 requirements, the owner of the non-BES radial line has no obligation to analyze or correct the Misoperation. The PRC-027 SDT received comments with similar concerns in its last revision. They have drafted language to ensure that coordination of non-BES Protection Systems between different Functional Entities. The PRC-004 SDT may want to consider similar language to ensure that all Misoperations which can affect the reliable operation of the BES are analyzed and corrected.
Group
Operational Compliance
Ed Croft
Yes
Yes
Yes
No
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
1) Please revise the Slow Trip – During Fault second sentence for clarity. We suggest: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation unless the high-speed performance has either been identified to meet the dynamic stability performance requirements of the TPL standards, or is required to ensure coordination with other Protection Systems.” 2) We suggest clarifying Definition (6) by replacing "is unrelated to on-site" with "the Protection System that operated is not directly associated with" as shown below to be consistent with page 17, and to exclude transfer trip testing: Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the Protection System that operated is not directly associated with maintenance, testing, inspection, construction or commissioning activities. 3) Add an Application Guideline example showing that transfer trip testing would not be considered Misoperation as well. Even though the BES interrupting device is at a different location than the testing error, the transfer trip composite system is involved. We suggest: "An operation that occurs during a non-fault condition but was initiated by remote transfer trip system maintenance, testing, inspection, construction or commissioning activities is not a Misoperation."
Yes
none
Yes
none
Yes

1) Unknown / unexplainable is the 'cause' of about 12% of Misoperations per NERC reports. An R3 'no further action' declaration example would be helpful. Perhaps your 'no action plan' declaration example on page 23 was intended for this. If so, please so state there. 2) Please replace 'reverse power' with 'overexcitation' on page 15 in the failure to operate for a non-fault condition section. Reverse power relays are usually excluded so the example is confusing as is.
1) Some entities presently use their PRC-004 reporting as a means of documenting CAPs. They may prefer to use your proposed data request under Section 1600 of the NERC Rules of Procedure for these purposes. Please change page 5 wording to "The data submitted as part of the data request will not be used by NERC or the Regions for compliance or enforcement purposes." 2) Compliance section 1.2 on page 9 states "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation." Please delete "and Measures M1, M2, M3, and M4" because entities must comply with Requirements, but Measures are not allowed to expand that scope. 3) In the first sentence of R2 on page 7, please add "first" before "cause" so it reads "Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the first cause of each Misoperation: …" Pages 19 and 20 make it clear that this is triggered by the first cause, but some entities may miss this application guidance. 4) Please include 'Composite Protection System' as a defined term that remains with this standard (similar to PRC-005-2 approach for Component, Component Type, etc.). Your definition on page 14 is fine, but move it up to just after the page 3 Definitions. Regarding commments for all questions 1-5 above: 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
Wryan Feil
Northeast Utilities
Yes
No
R1.1 second bulleted item states: If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. This requirement statement is confusing and should be revised to clearly describe the intent. Additionally, this statement requires action by more than one entity within the 120 day time period. There is no requirement for BES interrupting device owner to notify the owner of the protection system component identified as contributing to the misoperation prior to 120 days which could leave the protection system component owner no time to investigate and determine if the operation was correct or not as required in R1.1 and determine the cause as required in R1.2 (which also must be completed within the first 120 days). We suggest that the above statement be a separate requirement under R1 and be worded as follows: If the BES interrupting device owner cannot determine that the Protection System operation was correct, and concludes that protection system components owned by another entity contributed to a possible misoperation, the BES interrupting device owner shall notify the other owner(s) of the Protection System component(s) of their preliminary conclusions and provide any requested investigative information within 90 days of an interrupting device operation. It is suggested that a 90 day timeframe for this situation is still reasonable for the interrupting device owner and allows 30 days for the owner(s) of the Protection System component(s) to comply with the existing R1.1 and R1.2. During the 120 day review period, requirement 1.1 does not ensure that there will be adequate time for ALL Protection System owners to review the operation. If the BES interrupting device owner is tardy in informing another Protection System component owner, then that Protection System owner may not have time to perform a review. There should be some milestone within the 120 day review period where all Protection System owners need to be informed of the operation and their need to review it.

No
We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
No
Individual
Jonathan Appelbaum
The United Illuminating Company
Agree
Northeast Power Coordinating Council (NPCC)
Individual
Mark Yerger
Pepco Holdings, Inc Segment 1
Agree
Pepco Holdings Inc and Affiliates, Segment 1
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
Suggest Misoperation definition #6 be revised from “unrelated to on-site maintenance….” to “unrelated to maintenance….” to clearly allow as an exclusion, a Protection System maintenance or commissioning activity which results in an inadvertent remote end station trip. For example, a direct transfer trip scheme.
Yes
Since actual Misoperation data reporting will now be addressed outside of this standard, entity data communication requirements within this standard need to be consistent with respect to data reporting criteria. As an example, since there is no requirement for a contributing component entity owner to forward the required investigative and CAP data to the interrupting device entity owner, one would expect that reporting will be the responsibility of the Protection System contributing component entity owner.
Yes
No
Suggest “Composite Protection System” as listed in the Guidelines and Technical Basis section (page 14 of 24) be a defined term for this standard.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration believes that the latest version of the definition correctly captures the intent that the action of the composite Protection System is the gating factor in the determination of a Misoperation. The aggregate action of the primary, secondary, and pilot systems should form the basis of the expected performance, not each individual group of components. However, we still believe that the project team’s intent to allow Protection System owners some flexibility to determine when a “slow trip” occurs is not captured. We fully agree with your statement in the last Consideration of Comments that it is up to the owners to have “an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm,

and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.” However, unless the language is captured in the standard or the definition, CEAs may choose a different basis. In the extreme, they may determine that any delay outside the settings or manufacturer’s specifications to be a Misoperation – even if reliability is not threatened or monitoring equipment cannot resolve down to that level of granularity.
No
Ingleside Cogeneration agrees that the owner of the tripping device should own the investigation and bring in other entities as needed. In addition, R1 takes out any guesswork about the responsibilities of each Protection System owner who may have contributed to the Misoperation. What we still do not understand is the recourse available to the Protection System owner if the request for assistance from an adjacent entity is sent late. The requirement does not account for the fact that a notification may be issued weeks after the fact – the 180 day assessment deadline applies regardless. Under these circumstances, the recipient may be forced to declare that a cause was not found, as allowed by R3, and develop an action plan to investigate further. However, this leaves that owner in the position to explain the delay to auditors; which we do not believe is appropriate. Even more concerning, there appears to be nothing that stops the CEA from deciding that the reduced interval was adequate and assessing a violation as a result.
Yes
No
Ingleside Cogeneration shares the project team’s desire to retain a scholarly and cooperative approach to the assessment of Misoperations. However, we believe that the regulatory pressure will mount – particularly as NERC’s events analysis numbers continue to show Misoperations as a primary component in nearly every wide area outage. This means concepts that are implicitly understood today will be immaterial in the future. For example, it is easy to see that a CEA may assess a violation for a single missing relay operation evaluation out of hundreds that may have occurred during a wide-area weather event. Despite assurances that the CEA will take the circumstances “under consideration”, we are not convinced that that will always be the case. If the drafting team is reluctant to modify the definition of “Misoperation” or PRC-004-3’s requirements, there may be an opportunity to capture these understandings in a binding way in the RSAW. There is a new program that has been initiated by NERC to include Compliance representatives in the standards drafting process for situations just like these. If we are able to provide commentary on the auditors’ instructions captured in the RSAW, it would alleviate our doubts that understandings reached during the development phase would be retained when the standard becomes mandatory.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the response to our comments, but, we do not believe our issues have been resolved. First, on “Slow Trip”; however, we disagree with your perspective. The SDT is taking a relativistic approach to time, e.g., interpreting the words it drafted “slower than intended” as relating to whether the Protection System operated “fast enough to prevent additional harm” and not a more common interpretation of it operated slower than it was designed to operate. FMPA believes that an auditor would interpret this using the latter interpretation and instead ask for the design clearing time of the protection system as a comparison of whether actual operation was “slow”, e.g., if the system is designed to operate in 5 or 6 cycles and instead it operates in 7 or 8 cycles, fast enough to prevent backup protection from operating, but slower than designed, is that slow? If the SDT intends “slower than intended” to mean that it operates “fast enough to prevent any additional harm”, e.g., the clearing time of the back-up protection, then state that in the definition. The response to our comment (and the Application Guidelines) focuses on the owner of the Protection System “should have an understanding of the objectives of its Protection Systems”; that is not FMPA’s concern. FMPA’s concern is how an auditor will audit R1 and verify that the entity identified all misoperations, and how an auditor will interpret “slower than intended”. Second, FMPA commented last time

(commenting on R1) on the difficulty of measuring whether a fault actually occurred and where the fault in regards to the definitions of “Failure to Trip” and “Unnecesary Trip”. For both, an auditable investigation would need to determine if: 1) a fault actually existed, which can be quite difficult to verify for something like a lighnting strike with automatic reclosing; and 2) where the fault was; so that it can be determined whether or not the fault was “within the zone it was designed to protect”. In investigating tripping of BES Elements, a large number of those events are indeterminent, meaning that physical evidence could not be found. With microprocessor based protection systems, if may be possible to set up a sort of event recording function that may be able to provide evidence of fault condition and roughly where a fault was; however, with electromechanical relays, that is not possible without installing additional equipment. Is the SDT intending to require a form of event recording at each substation so that the existence and location of a fault can be determined for every protection system trip? If no evidence of a fault exists, would the default assumption be that everything operated as intended unless the evidence of protection system operation indicated otherwise (e.g., both primary and backup systems operated)? If that is the intent, then that intent should be stated within the requirements. Third, how would a high impedance fault be treated? Such a fault could occur within the relay reach, but, the impedance of the fault could in essence cause the fault to appear further away than it actually is. For instance, assume a line is protected by an instantaneous ground overcurrent relay protecting about 70% of the line and by an inverse time ground overcurrent relay as local backup. And let’s say a high impedance fault occurs 50% of the length of the line, but the impedance of the fault reduced the fault current to below the instantaneous relay setting such that the inverse time ground overcurrent relay operates instead. Is that a misoperation because the instantaneous ground overcurrent relay failed to operate for a “Fault within the zone it was designed to protect”? Which leads to the ambiguity of the phrase “within the zone it was designed to protect”. Does zone mean a distance as derived from the relay settings, or is it the relay settings themselves? If it is the relay settings themselves, then FMPA suggests changing the phrase to eliminate “zone” and instead refer to the actual protection system settings. Fourth, FMPA is also concerned about how “composite Protection Systems” works, especially with the combination of “within the zone it was designed to protect”. For instance, let’s assume Line 1 has typical stepped disctance scheme of zones, 1 through 3, and let’s assume the adjacent Line 2 has a fault and there is a failed breaker at the intermediate substation. The breaker is not part of any protection system, but, the zone 3 remote backup relay of Line 1 operates to help clear the fault on Line 2, which is a correct operation. So, is Line 1’s zone 3 relay part of Line 1’s composite Protection System, and if so, then there is not a single “zone” for composite Protection Systems, which again adds to the ambiguity of the phrase “within the zone it is designed to protect”. Fifth, some misoperations are due to mistakes made by protection engineers, e.g., mistakes in establishing relay settings; so does: “within the zone it was designed to protect” the actual design of the protection engineer, e.g., the mistaken relay setting, or what the design should have been? If the latter, how will the ‘what the design should have been’ be determined? If the SDT has not already done so, FMPA recommends involving NERC and RE enforcement staff to discuss how R1 would be audited in combination with these definitions.
No
First, as currently drafted, R1 means that each investigation into a protection system operation is auditable, which in turn means that the definition of misoperation as discussed in question 1 need to be easily measurable. Please see discussion in question 1 about the difficulty in measuring: 1) “slower than intended”; 2) whether or not a Fault occurred; and 3) whether or not that Fault was “within the zone it was designed to protect”. Second, there are numerous Protection System operations wtihin a year, which results in a high-volume problem similar to those found in CIP standards, COM-003 and PRC-005. FMPA continues to recommend, as we did last time, that this standard would be better served by instituting internal controls language for R1 similar to what the CIP v5 and COM-003 SDTs adopted. Adopting such language would have the additional benefit of allowing the entity more latitude for how they deal with the ambiguities described in response to question 1. Third, FMPA commented last time that there ought to be an exception for Acts of Nature such as hurricanes and other natural disasters with, at minimum, the 120 day rule being waived. In response to FMPA’s comments, the SDT agreed with this concern. However, rather than change the standard, the response was: “The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines

outlined in this standard." That means that the entity would still be in violation of the standard if it were not able to investigate all relay operations that occurred dueing a natural disaster. This is not acceptable to FMPA and we desire language to extend the time of the investigations as a result of Acts of Nature (e.g., a named storm, an earthquake that resulted in severe damage, etc. – maybe anytime a State's Governor declares an emergency) to a longer hodl th entity to the 120 day time period, e.g., but instead to a longer period such as 240 days, to allow time for more pressing disaster recovery efforts, without actually incurring multiple violations to the standard that would remain on the entities "record". Fourth, there is no recognition that it is possible to have a condition where it cannot be determined whether the operation was correct or a Misoperation, e.g., if the location of the fault cannot be determined, or whether a fault condition actually existed or not, especially for something like a trip with successful reclose. See the second point made in response to question 1 for further discussion.
First, R4 uses the phrase "as needed." In doing research for legal precedence interpreting the phase "as needed," both in terms of contract interpretation and statutory construction, numerous cases throughout the country make it clear that, unless this phrase is clearly defined in the context in which it is used, this phrase is ambiguous and will only lead to conflict. For instance, the phrase indicates that (1) there is a level of discretion involved regarding an action that must be taken, and (2) someone must make a determination as to when such action is deemed "needed." However, the standard is silent both as to what factors trigger the exercise of discretion and who makes the determination that a change to the CAP is "needed" - the entity or compliance staff. In this regard, FMPA recommends making it crystal clear what "as needed" means. For example, it could state "as needed to reflect any CAP revisions made by the responsible entity, as determined at the sole discretion of the responsible entity." Second, R4 should recognize that not every investigation of a Misoperation ends in a CAP, e.g., those where no cause was found in accordance with R3.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
R1 and the rationale for R1 assume that the BES interrupting device owner and the Protection System owner have been talking and R1 requires identification and review of each operation within 120 days. R1 should require that the BES interrupting device owner notify the Protection System owner or vice versa, depending on which entity discovers the event first, within a specific time after the entity is aware of the operation in order to ensure that the other entity has adequate time within the 120 day period to finish the review.
No
R4 VSL wording is not clear as presently stated; "The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4." It might not be intended, however this wording implies that all CAP's must be revised and if not revised there is a compliance issue. The wording should state; "A CAP revision was needed in accordance with R4 and the responsible entity failed to make the revision."
Yes
There are some examples of CAP in the document. Adding examples relative to my comment in question 5 would be beneficial.
R2 requires a CAP except in cases where the entity can "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" R2 does not recognize that every CAP requires resources to complete and that the industry has limited resources. There are cases where the required resources to complete a CAP at multiple locations provides minimal increase in reliability. If these low productivity CAPs are required to be completed the net result is a decrease in BES reliability since other more productive work will not be done due to lack of resources. The entity should be able to state the CAP was completed at only the affected site and was not rolled out

system wide due to poor ratio of resources required to reliability benefit gained.
Individual
Daniel Duff
Liberty Electric Power LLC
No
I agree with the position of the Standards Development Team of the North American Generator Forum, which states: The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The "same 120 days" could place an impossible burden on an entity notified late in the 120 day period. Notification that an issue with an entity's system contributed to a misoperation should start a new compliance clock.
No
Agree with the comments of the Standards Development Team of the North American Generator Forum, which state: The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
The standard would be simplified by combining R1 through R4 to state: R1 For each activation of a BES interrupting device initiated by a Protection System, the entity shall identify the cause of the operation. R1.1 If the activation is determined to be a misoperation, the entity shall develop a corrective action plan, or explain in a declaration why a CAP cannot reasonably be instituted. R1.2 If no cause can be determined, the entity shall develop an action plan for further investigation, or explain in a declaration why no further action is warranted. R1.3 All action plans shall be developed within 180 days of the operation, or notification of an operation of a BES interrupting device caused by the RE's Protection System. R2 All action plans developed under R1 shall be implemented or revised as needed until complete. The additional detail in the current version (work timetables, other facilites) should be moved to the measures, as they are the output of the requirements.
Individual
Joylyn Faust
Consumers Energy
No
There still seems to be a contradiction in R1 regarding the responsibilities of the BES interrupting device owner (IDO) vs. the Protection System owner (PSO) when owned by different entities (as we commonly have on the 138 system). The breaker, other than the trip coils and CTs, is not part of the Protection System, so the responsibility to investigate operations initiated by a protection system should be with the PSO. NERC's response below to Q4 seems to agree with this (regarding documenting, CAP, and reporting), but R1 still places responsibility for investigation on the IDO. As a matter of fact, the Rationale for R1 added into draft 3 the statement "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection

System." When an interrupting device operates, logically the IDO would investigate why their device operated. As soon as the IDO finds out that the operation was initiated by a protection system (the situation described in R1) they should then only have to notify the PSO of the situation (the PSO may not be aware of a protection system operation). The IDO would not be in the best position to investigate, and should not be validating Protection System operations for the PSO. The seems to be mostly a contradiction of the wording in R1 vs. the Rationale section. If the Rationale is not included in the final version of the standard, I could probably agree with the wording of the rest of it.
Individual
Daniela Hammons
CenterPoint Energy
Yes
No
CenterPoint Energy is concerned the wording of R1.1 to review a BES interrupting device "operation" within 120 days and the wording of R1.2 to investigate a "misoperation" within the same 120 day period of a BES interrupting device operation could be unworkable. The owner of the BES interrupting device could notify the owner of the Protection System component identified as contributing to the Misoperation well into the 120 day period, which would give the Protection System component owner little time to investigate and determine a cause. CenterPoint Energy recommends R1.2 wording be the following: "The owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified, by the latter of 120 days of a BES interrupting device operation or 30 days after receiving notification from the owner of the BES interrupting device."
Individual
Kenn Backholm
Public Utility District No. 1 of Snohomish County
Yes
No
See response under Question #5 with specific recommendations to implement Internal Controls.
No
The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Group
ACES Standard Collaborators
Ben Engelby
No

(1) The term “composite” Protection System is unclear, used inconsistently and should be defined. Based on the first sentence on Page 14 of the Guidelines and Technical Basis section, it appears that all Protection Systems protecting an Element are intended to be included in composite Protection System. That is any primary, secondary, backup, pilot and non-pilot relay schemes for a given Element would be included in its composite Protection System. If this is the case, we suggest just writing a definition so it will be clear where the term comes from and what the meaning is. However, it is not clear that the term is even needed since the definition of Protection System would already include all of these Protection Systems. The definition includes “Protective relays which respond to electrical quantities.” The inconsistent use of “composite” in the standard documents only creates more questions for the need of the definition. For example, on page 14 of Guidelines and Technical Basis section under the section (1) title, the “overall performance of the Protection System for the Element it is designed to protect” is used. This is understood to be all “protective relays” including secondary, backup, pilot and non-pilot relay schemes. As defined, Protection System includes the plural use of protective relays so all could be included. (2) Why does the definition need an introductory sentence? The clarifying statement “any of the following is considered a Misoperation” provides the same outcome. Also, several of the sub-parts of the definition discuss the “overall performance of the Protection System,” so this introductory sentence seems redundant. Instead of adding confusion, we recommend that the drafting team strike the entire introduction sentence of the definition. (3) For sub-part “3. Slow Trip – During Fault” of the definition, we recommend revising the second sentence. It is a run-on sentence, uses incorrect grammar, contains a triple negative statement, and is confusing. We recommend revising the sentence to clearly state when delayed fault clearing should be excluded and what conditions must be met before the operation is not to be considered a Misoperation. For sub-part “5. Unnecessary Trip – During Fault” of the definition, we believe that the revised sentence now overlaps other sub-parts of the definition. “A Protection System operation for a Fault for which the Protection System is not intended to operate” is almost the exact definition of Misoperation in the introductory sentence. Nothing in this sub-part discusses an unnecessary trip. The phrase “not intended to operate” could apply to all of the other sub-parts because a failure to trip, slow trip, or unnecessary to trip would be the result of a Protection System not operating the way it was intended. More detail is needed for this sub-part.
No
(1) Also it is still unclear who has the ultimate responsibility for identifying and reviewing each operation if the interrupting device and Protection System are owned by two or more parties. What should occur if there is disagreement over the responsibility or the ownership of a component? What if multiple parties owned components that contributed to an operation or a Misoperation? Are both parties responsible? The rationale may provide additional guidance, but the words in the requirements are unclear. (2) “BES interrupting device” is not a defined term and is vague and ambiguous. We understand that devices that interrupt fault current, such as circuit breakers and circuit switchers would be included but what other devices such as motor operated disconnects? Are they not included because they don’t interrupt any current? What if they are equipped to interrupt charging and load current? Failure to define “BES interrupting device” could result in an informal definition that results in inconsistent enforcement by including components outside of the scope of what is intended to be a BES interrupting device. This term adds uncertainty and creates opportunities for multiple interpretations.
No
(1) The measures are not consistent with the revisions to the requirements. For instance, Requirement R1 requires the owner of the component that led to the Misoperation to identify and review its performance. However, the Measures require the applicable entities to have evidence without any statement regarding the ownership of Protection Systems or circuit breakers.
No
(1) If the drafting team intends to move forward with “composite Protection System,” we recommend adding it as a new proposed definition. After reading the technical guidelines, we are not persuaded that the drafting team has articulated the difference between a Protection System and a composite Protection System. A proposed glossary term would allow industry the opportunity to provide the feedback as to whether an additional term is needed in order to have the proper scope for identifying Misoperations.
(1) We recommend introducing the term “BES interrupting device” as a new definition with clearly defined parameters. (2) We would like more information on the Section 1600 data request for

Misoperation data. Also, if a data request is going to be utilized, will registered entities still need to continue reporting under PRC-004-2? This would be a redundant process and we encourage NERC to coordinate the timing of the data request to take the place of the current reporting requirements. Further, we disagree with the evidence retention section of this standard. TO, GO, and DP are audited on a six-year cycle, which is too long of a timeframe to retain evidence. We suggest shortening the amount of time to three years, unless there is an open or ongoing investigation, action plan, or CAP. If there is a section 1600 data request, why does the data need to be retained? NERC already has the information. (3) This standard is another candidate for implementing internal controls, and should not contain “zero-defect” language. For example, an entity should be able to have controls in place to determine whether Misoperations are being identified, assessed and corrected. This is the essence of PRC-004-3, and therefore should be revised to include these concepts. There should not be zero-defect penalties if an entity has controls to catch errors and fix them. Currently, the standard would penalize an entity for each instance of noncompliance. (4) We continue to be confused by the interaction of Requirements R1 and R3. While R1 does not compel the protective relay owner to identify the cause of a Misoperation, it does compel the owner to investigate the Misoperation. One would presume an auditor would expect investigative actions conducted for Requirement R1 to be reasonable. However the application guidelines section for Requirement R3 states clearly on page 14 that this requirement only applies if “reasonable investigative actions have not been exhausted”. Thus, it would appear that Requirement R3 could never apply without a violation of Requirement R1 Part 1.2. We think the interaction of these requirements need further clarification. Furthermore, we suggest that Requirement R3 could actually be made part of Requirement R1 which would help alleviate the confusion. For example, Part 1.2 could have a subpart that states that an action plan should be developed for any reasonable investigative actions that may require more than 120 days to complete. Another part could be to document why the cause cannot be identified. (5) Since UVLS is specifically excluded in the applicability section does it make sense to include it under voltage conditions in part 2 and 4 of the Misoperation definition? (6) Why can’t the implementation requirement R4 be included as a Part of the other requirements? Furthermore, it is questionable if it is even needed for FERC has stated in past orders that there is an implied obligation to implement plans, policies and procedures when a requirement compels their development. This requirement is similar to the types of standards that would be subject to Paragraph 81. (7) Thank you for the opportunity to comment.
Group
JEA
Tom McElhinney
We believe that the issues should be handled through modification of PRC003 not PRC004.
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Pepco Holdings Inc and Affiliates
Group
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes
Southern Company supports the SERC comments and are including the following additional comments: 1. We believe that the same consideration of whether or not the composite Protection

System operated as intended could be addressed with a much simpler definition: "The failure of the Protection System to operated as intended, including failing to trip when it should have, unnecessarily tripping with it should not have, or tripping more slowly than intended." This definition allows the Protection System owner to evaluate the operation and determine if it operated appropriately. 2. We believe that the shift in focus to "composite" and "overall performance" does not clarify the ability to identify misoperating Protection System components.
No
1. The requirement R1 can be simplfied by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. 2. The notification and response requirement of R1 is not needed, as the owner of the Protection System that operated is already required to investigate each operation in Requirement R1. An additional requirement for notifications and responses is superfluous. 3. There is a timing problem with R1.2 for the protection system owner who is notified on day 119 following a protection system operation. It is not reasonable or just to require this protetion sytem owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a misoperation of another entitiy's protection system.
No
1. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. 2. The severe VSL for R1, R2, and R3 can be simplified by changing a few words in the first item of each requirement. For R1, change "...entity performed the actions in ... and 1.2 in more than 170..." to "...entity did not perform the actions in .... and 1.2 within 170 ...". This would allow the 2nd and 3rd items in the OR statement to be eliminated. For R2, change "entity developed a CAP, or a declaration .... R2, more than 90 ..." to "entity did not develop a CAP or a declaration ...R2 within 90 ...". This would allow the second part of the OR statement to be eliminated. For R3, change "entity developed an action plan, or made a declaration ... R3, more than 230 ..." to "entity did not develop an action plan or make a declaration ... R3 within 230 ...". This would allow the second part of the OR statement to be eliminated. 3. The VSL should be have a weighting factor in the % of operations not analyzed (otherwise it is one strike and you're out and this could be one event out of many). Equal severity for 1/10 events is not just compared to 1/100 events.
Yes
Southern Company supports the SERC comments and are including the following additional comments: 1. In various locations of the text, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misopeartion rather than simply that they are not misoperations (we believe that they are still misoperations). We believe that entities should be allowed to determine whether or not the Protection System operated appropriately. This is inherent in our suggested simpler definition of Misoperation through including "than intended". 2. In the text for section 6 of the Misoperation definition, we disagree with the phrase "An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspetion, construction or commissioning is not a Misoperation." This is obviously an unnecessary trip - other than fault. This should be included in a list of non-reportable misoperations.
Southern Company supports the SERC comments and are including the following additional comments: 1. By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms as well as the term ‘action plan’ in R3, it is unclear what differences exist between a CAP and an “action plan” as written in PRC-004-3. Please modify language to be consistent or add language that describes the intent and difference between a CAP and an “action plan”. 2. R2 and R3 should be restructured such that it is immediately apparent that R2 deals with Misoperations with an identified cause and R3 deals with Misoperations without an identified cause. This could be accomplished by phasing that condition first in the requirement so that the required actions that are bulleted immediately follow the "shall" such as: "R2: For each Misoperation with an identified cause, the entity shall either develop a CAP ... or declare why ..." and "R3: For each Misoperation without an identifed cause, the entitiy shall either develop an action plan ... or declare why ..." 3. R4 should be re-structured to flow more smoothly, as follows; “R4. Each entity shall implement and revise, as needed, each CAP or action plan. 4. The three bullets found at the top of page 6 of draft 3 of the standard

should be the three requirements of this standard. Has any consideration of making those three items the actual requirements? 5. Please consider using the phrase "component that misoperated" rather than "component that contributed to the misoperation" in the standard for clarity. 6. There is too much unnecessary date bookkeeping in the Requirements. We recommend deleting all existing date clocks linked to each event and specify a resolution time limit for investigative action plans/CAPs to be the filing date deadline for each quarter. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability. The establishment of investigative action plans and/or completion of necessary Corrective Action Plans in a timely fashion are the actions which will affect the reliability of the Protection System. 7. In reference to the above comment, if the timeframe are to remain, the SDT is strongly encouraged to move toward an internal controls format for this standard.
Individual
David Jendras
Ameren
Yes
Yes
No
(1) We disagree with the VSL escalation, for R1, R2 and R3, from Moderate to High to Severe at 10 days interval each.
Yes
(1) Please clarify the sentence on page 17, the second to last paragraph, "Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations" by putting it in a new paragraph and including some examples. Does the protected Element have to be out of service? Is this intended to include human error (e.g. bumping the panel) caused trips by personnel other than Protection System maintenance personnel? (2) Please add "completed" on page 20, near the bottom, so that the title reads " The following are examples of completed Corrective Action Plans (CAPs):" (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.
Group
PPL NERC Registered Entities
Brent Ingebrigtson
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: • The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. • Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. • The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). • Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own…" by the required time frame. There is a possible time coordination issue for identification and review of misperations with R1.2. As stated in the proposed

standard, R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. If timely communication of misoperation information is delayed by a Protection System component owner, the BES interrupting device owner could possibly bear the responsibility of not meeting the 120 day reporting requirement per R1. Fundamentally, R1 frames the time period for reviewing and analyzing a misoperations where multiple responsible entities are involved. However, R1 does not take in to account that one entity's analysis may be dependent upon the other's final analysis and that parallel review of misoperations are not possible. More consideration should be given to the cases where one entity's actions impact another's ability to meet the requirements of R1. However, concur in overall concept with clarifying coordination roles between BES interrupting device owner and the Protection System owner.
No
The VSLs are hard-wired to response/reporting timelines specified per R1-R3. Some consideration should be given to technical complexity and circumstance of the SPS Misoperation. The R1 evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.
Yes
The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
The PPL NERC Registered Entities (PPL Electric Utilities, PPL Generation LLC, PPL Energy Plus, LG&E and KU Services) are in agreement with the spirit of the North America Generator Forum Standards Review Team comments for the successive ballot for Project 2010-05.1 Protection Systems: Misoperations. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard are possibly sufficient requirements for this standard. Has any consideration been given to making those three items the actual requirements?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No
No
No
The documentation requirements for maintaining a database of every operation of a BES interrupting device, which are laid out in Measure M1, represent a significant step change in documentation requirements when compared with the current misoperation analysis and reporting requirements. Unintentional mismanagement of a database that identifies every operation by time, date, and date of review during a six year audit window poses no significant risk to the reliabile operation of the Bulk Electric System. However, enforcement of this measure will likely identify clerical or other

unintentional errors made during the process of tracking misoperations that will impede NERC’s ability to address violations that pose a moderate or severe threat to the reliability of the Bulk Electric System. The underlying objective of the data compiled in the measure appears to be a ‘best practice’ method for retaining data necessary to meet the quarterly reporting requirements for misoperation reporting; specifically reporting of the ‘total number of operations’. While it is understood, that NERC is utilizing this quarterly reporting data to develop metrics to track the performance of BES Protective Systems, the required implementation of a prescriptive tracking method in a Reliability Standard does not balance the need and method for addressing the need, and compliance with the quarterly reporting of misoperation data is already driven by NERC’s Rules of Procedure. The SDT should consider modifying Measure M1 in such a way that it requires misoperation analysis reports (Corrective Action Plans and Action Plans) to include the level of detail addressed in Measurement M1 (time & date of operation, date analysis determined it was a misoperation, etc.). This modification would address the need to ensure that misoperations are appropriately analyzed within a reasonable amount of time while avoiding the implementation of a Reliability Standard requirement that could create enforcement actions that hinder NERC’s ability to address potential violations that pose a moderate or serious threat to the Bulk Electric System.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
Yes
No
ramping up the violation level simply on the number of days that pass to complete the analysis does not seep appropriate for situations where the discovery may have been delayed in the first place
Yes
Generally, the standard does not seem to address the reporint of no events now being required by the RE, especially for entities that have only a few devices, the reporting burden for non-events shoudl be clearly eliminated. It is not clear that it is eliminated. Only the reporting of actual misoperations should be required as defined.
Individual
Cole Brodine
Nebraska Public Power District
Yes
Yes
Yes
Yes
The drafting team should review the BES Definition drafting team documents and evaluated how it relates to misoperations. It would be desirable to avoid any disconnects or conflicts between these definitions and standards. Some BES Definition drafting team documents indicate individual wind turbine generators are part of the BES. Is misoperation data desired down to this level? During Webinars explaining the BES definition documentation questions were asked regarding how the BES documentation helps identify or determine what protection systems are included for PRC-005. The BES drafting team stated that protections systems for PRC-005 are not to be defined by the equipment identified in the BES definitions documentation but instead are to be defined the PRC-005 standard and documentation. Would this be the case for PRC-004-3 as well?

Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Individual
Scott Langston
City of Tallahassee
No
Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.
No
There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation.
No
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
Some of the scenerios for possible mis-operations are too vague. For example, what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation; however, it would still protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line, unless there is physical damage, there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you cannot first confirm what caused the fault.
No
There should be some provision in the standard to take into account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example, if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company, it may take longer than 120 days to perform a thorough investigation.
No

Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Florida Municipal Power Agency
Individual
Michael Falvo
Independent Electricity System Operator
No
NPCC uses different terms, such as failure to operate (not operating when required) vs misoperation (operating when not required). We think that the definition here has the intention of defining more generally an "incorrect operation", and perhaps the "incorrect operation" should be used for both different terms.
No
1 We belive that R1 should be written more clearly, by saying that: “Within 120 calendar days of a BES interrupting device operation casued by a Protection System operation, each Transmission Owner, Generator Owner, or Distribution Provider - that owns the BES interrupting device - shall identify and review each Protection System Operation.” 2 Also, there is a lack of clarity on which entity is responsible for developing and implementing a Corrective Action Plan. We believe that there has to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible for the CAP, especially in view of the rationale provided in the text box for R1, whose excerpt says: “The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”. We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest revising the leading part of R2 to: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying….”. The Same revision should apply to R3, as follows: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of the associated BES interrupting device operation,…..” Further, though not explicitly stated, we assume that the owner of the component that contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.
Yes
Yes
Generally speaking, the standard is difficult to read, focusing on how instead of what. The drafting team should strengthen the description of the outcomes, and try to reduce the reliance on the application guideline and the rationales. (One has to read the rationales before understanding the meaning of the requirements.)
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes

Yes
Yes
Yes
By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an “action plan” as written in PRC-004-3. Both appear to be the same until the Rationale for R3 states “implementing an action plan of additional investigation/monitoring may determine cause and lead to the development of a CAP in accordance to Requirement R2.” Oncor recommends that additional language be added that describes the intent and difference between a CAP and an “action plan”. Oncor would also like clarification as to what authority the CEA holds in determining the effectiveness of the corrective actions detailed in the CAP and/or “action plan”.
Individual
Roger Dufresne
Hydro-Québec Procution
Yes
No
In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept(reliability of the BES) implies the analysis of all the events that occured on the BES have to be done, even if the event do not affect the reliability of the BES.
No
In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that occurred on the BES have to be done, even if the event do not affect the reliability of the BES.
No
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
No
Please see answer to Question 5
No
Please see answer to Question 5
No
Please see answer to Question 5
LADWP recommends that the Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. LADWP also recommends that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Individual
Laurie Williams
Public Service Company of New Mexico

Yes
Yes
Yes
No
None
Individual
Bret Galbraith
Seminole Electric
The NERC STD defines a Slow Trip as a “Protection System operation that is slower than intended… .” (emphasis added). My preliminary read of this language was that if the Protection System operated slower, i.e., took even 1 cycle longer in time to operate, than how it was intended to be set, that such delay would be a Slow Trip. However, reading your responses to comments, it appears that “time” is not the measure of compliance, but in fact, the compliance metric is based on intended protective objective. By this I mean, if the overall goal of protection is met, then there is no slow trip no matter how much time has passed. To clarify even more, so as long as no additional harm has occurred during the time delay, time is not the measurement for compliance, but harm to the protected equipment is the compliance measure. With that said, can you please describe in some more detail how this compliance metric, i.e., additional harm, will be documented and audited?
1. The Proposed PRC-004-3 combines PRC-004-2a and PRC-003-1. This project is applicable to a “Distribution Provider” whereas PRC-004-2a is applicable to a “Distribution Provider that owns a transmission Protection System.” Does the STD believe that the additional caveat should be added to the Distribution Provider (DP) applicability, i.e., that the DP need to own a transmission Protection System? 2. In the “Purpose/Industry Need” section that the STD developed for this Project, the STD states that because PRC-003-1 was never approved by the Commission, “there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2… This could lead to a potential reliability gap.” (Emphasis added). This infers that there is a need for some form of standardized regional mitigation requirements. When NERC drafted PRC-003-1, NERC made RROs the applicable entity in order for each RRO to “establish, document and maintain is procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations.” (See R1. of PRC-003-1). However, in the proposed action, PRC-004-3 does not appear to require any such regional processes for misoperations mitigation. In fact, the new proposed Standard is not even applicable to RRO as the new standard does not require the RRO to perform any action. It does not appear that the new draft Standard mitigates the deficiency left by the non-approval of PRC-003-1 and so this should be addressed via the addition of some form of regional analysis requirement.
Group
Bonneville Power Administration
Jamison Dye
Yes
No
(1) The changes made to R1 are an improvement over the previous draft, but they still do not adequately clarify the responsibilities. Both the Rationale for R1 (blue box) and the Application

Guidelines indicate that the responsibility to investigate operations is placed on the owner of the interrupting device. However, BPA believes that the actual wording of R1 does not necessarily place the responsibility on the owner of the interrupting device. Instead, R1 places the responsibility on the TO, GO, or DP which has an interrupting device operation in its facility. Since it is quite common in the industry for TOs, GOs, or DPs to own interrupting devices within another entity's facility, R1 will sometimes place the responsibility on the owner of the facility where the interrupting device is located instead of on the owner of the interrupting device. In addition, the bullet points of R1 address the cases where the entity owns both the interrupting device and the protection system and where the entity owns the interrupting device but not all of the protection system, but there is no bullet point to address the case where the entity owns the protection system but not the interrupting device. It is not unusual for the owner of a facility to own a protection system but not the interrupting device that is operated by the protection system. Because it is vital that there is no ambiguity about who is responsible to initiate the investigation when an interrupting device operates, BPA recommends that the responsibility be placed on the owner of the protective relays which caused the interrupting device to operate because the owner of the protective relays will have access to the primary information that will determine how the investigation should proceed. After the owner of the protective relays makes an initial investigation, the owners of the interrupting device or the owner of other components of the protection system can be notified to investigate their part of the protection system. If the responsibility to initiate the investigation is placed on the owner of the interrupting device, that entity will have to immediately turn to the owner of the protective relays to start the investigation. (2) The use of Facility as defined by NERC in Requirement 1 does not make sense. As used in Requirement 1, Facility seems to indicate a substation or switching station, which is not in agreement with the NERC definition, which is a set of equipment that operates as a single element. BPA recommends that Facility not be used in Requirement R1 to avoid this problem.
Yes
No
R2 requires each TO, GO, or DP to develop a corrective action plan, but it does not indicate which TO, GO, or DP must do this. Is this intended to be the TO, GO, or DP that owns the interrupting device or the TO, GO, or DP that owns the protection system? BPA recommends the following wording for the beginning of R2: Each TO, GO, or DP that owns a component of a protection system identified as contributing to a misoperation, as determined per R1, shall within 60 calendar days of identifying the cause of each misoperation: (insert bullet points for R2). Similar to the comment above for R2, BPA believes that R3 does not make it clear which TO, GO, or DP the requirement applies to. BPA recommends that the entity identified by R1 as required to initiate the investigation of an interrupting device operation (BPA believes this should be the owner of the protective relays) should be the entity required to complete the actions in R3. BPA believes that similar to R2 and R3, R4 should be more specific about which TO, GO, or DP the requirement applies to. The last paragraph of the Background section states that where PRC-004-WECC-1 overlaps with this continent-wide standard, entities are expected to comply with the more stringent standard. In our comments to the previous draft, BPA suggested that the Background section simply state which of the standards takes precedence instead of leaving it to the entities to determine which standard is more stringent. The response to this comment was that entities are required to comply with both the continent-wide standard and any applicable regional standards. This response seems to contradict the Background statement. BPA requests clarification on whether entities are expected to comply with both standards or only the more stringent standard, and how an entity should determine which standard is more stringent as the standards cover very different issues. BPA believes that if an entity is expected to comply with both standards, that should be stated, or perhaps this part of the Background statement should be removed.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes

No
Austin Energy agrees with Luminant’s comment and copies it here for convenience. Requirement R1 requires all BES interrupting device operations be reviewed within 120 days. Under the Application Guidelines (Definition of a Misoperation - item 6 (page 17)), reverse power relaying used for normal unit shutdown is excluded. We recommend that this clarification be included in the Standard; either in language in the Definition of a Misoperation (items 2, 5, and 6) or in Requirement R1.
Yes
Yes
Austin Energy (AE) recommends the following changes in the Guidelines and Technical Basis section: (1) Remove the reference of reverse power relaying from item #2. This reference can be confusing because the protection scheme is used for safe shutdown of a generating unit. A substitute example would be “A failure of a “primary” loss of field relay is not a failure to trip Misoperation as long as another component of the generator’s composite Protection System opertated to shut down the generator.” (2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. AE believes this would clarify what relay systems are excluded before reading the parts of the definition and requirements. (3) The second paragraph on page 26 of the redline, which reads “With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days” is not consistent with the Standard Requirements and should be removed. The standard requires CAP development within 180 days, not CAP implementation or completion in 180 days.
(1) For events where a BES breaker operates but the Registered Entity does not own all of the Protection Systems, it is possible the other owner would not be notified until 120 days has elapsed. This is counter the the expectation of the drafting team that “it is expected that both entities will work together to investigate the cause of the operation.” Austin Energy (AE) recommends re-writing the bullets of R1 to require notification within a set number of days (AE recommends 15 calendar days) and then require the entities to work together as necessary. AE provides language revisions for consideration: R1.1. Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. --If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation. --If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, notify the other owner(s) of the Protection System component(s) within 15 calendar days. --The BES interrupting device and Protection System component owner(s) notified by the BES interrupting device owner shall work together to determine if there was a correct operation or a Misoperation of their component. (2) By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an Action Plan in the standard. They may appear to be the same. AE believes the intent of the action plan is to document an investigation plan, so recommends that additional language be added to the Rationale box for R2 that describes the intent of a CAP (as Corrective Action to avoid future recurrance) and an action plan as an investigation or other non-Corrective plan of action to investigate the cause of a misoperation or to determine if a misoperation has occured. (3) AE appreciates the efforts of the Standard Drafting Team and supports the goal of keeping the misoperation identification and correction processes as short as possible. There can be cases where extra time is necessary and the entire process may take longer than 180 days. The Standard allows for these extreme cases as written, assuming an action plan allows for the additional investigation of an operation or misoperation. For instance, if the cause of a misoperation cannot be identified, the entity may create an action plan to further research/analyze the cause (possibly the entity must ship equipment back to the OEM for cause determination). Once the cause is identified, then the Corrective Action Plan must be developed within 60 days. AE recognizes, and agrees with the Standard Drafting Team’s intent to ensure active analysis and appropriate corrective actions are adequately considered and/or implemented. Although it is likely there is sufficient time to analyze operations, identify misoperations and take corrective action for most events within the standard as written, there is a significant administrative burden involved to demonstrate action plans and/or corrective action plans are developed within the proper timelines. Therefore, although AE believes the timelines are workable as written, AE provides the following

alternative recommendation (4) Remove all of the required timelines and instead require the investigation/action plans and Corrective Action Plans only. These action plans and Corrective Action Plans contain timelines that must be followed by their very nature.
Group
Western Electricity Coordinating Council
Steve Rueckert
Sacramento Municipal Utility District
Yes
WECC believes that an Internal Controls Process with Risk Based requirements should be implemented in this standard.
Individual
E Scott Miller
MEAG
Agree
Southern Company Services - Generation