Individual or group. (53 Responses)
Name (33 Responses)
Organization (33 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
Question 1 (47 Responses)
Question 1 Comments (53 Responses)
Question 2 (44 Responses)
Question 2 Comments (53 Responses)
Question 3 (44 Responses)
Question 3 Comments (53 Responses)
Question 4 (46 Responses)
Question 4 Comments (53 Responses)
Question 5 (46 Responses)
Question 5 Comments (53 Responses)
Question 6 (37 Responses)
Question 6 Comments (53 Responses)
Question 7 (40 Responses)
Question 7 Comments (53 Responses)
Question 8 (33 Responses)
Question 8 Comments (53 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Comments regarding requirement R1 can be found in the response to Question 8. Additionally, suggest clarifying requirement R1 by adding the wording “for all design criteria events” so as to make it read: R1. Each Planning Coordinator shall, for all design criteria events, at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any:
Yes
Comments regarding requirements R2 and R3 can be found in the response to Question 8. Splitting requirement R2 into two requirements adds clarity.
Yes
Requirement R4 continues to be a combined TO/GO requirement. For clarity, R4 should also be split into two requirements--one to address the GO obligations by applicable requirement, another to address the TO obligations by applicable requirement.
No
A CAP is developed to correct a problem after the requirements of a standard are implemented. The Implementation Plan should address meeting the obligations of the standard’s requirements. The Implementation Plan would also address the annual identification of Elements. This would allow for the removal of requirements R5 and R6. Generator Owners and Transmission Owners need more time subsequent to the identification of load-responsive protective relays to perform a thorough evaluation. The requirement should provide at least 180 days to perform the evaluation. This will allow for a more complete response than can be obtained in 60 days. If the CAP is kept, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. The length of time an entity has to complete corrective actions should be specified. 180 calendar days is a realistic length of time.
No

Twelve months is not adequate to prepare for this standard as written. The Drafting Team should change the Implementation Plan to 24 months. The implementation could be improved by adding when the performance of requirement R1 is due. Is the PC supposed to complete its R1 analysis based on the effective date of the Standard 12 months after FERC approval, or 12 months after FERC approves the Standard then the PC has to complete the study for the calendar year? This can be difficult depending on when FERC approves the Standard. We suggest the revision to 24 months and stating that the PC is expected to complete the identification required by R1 in the calendar year that the requirement becomes effective. This removes the concern of what month FERC approves the Standard.
Yes
The wording of the Purpose should not have been changed. The existing wording" do not trip" is definitive; the proposed wording "…are expected to…" leaves room for questioning. If the proposed wording is kept, suggest that the Purpose read: To ensure that load-responsive protective relays are not expected to trip in response to stable power swings during non-Fault conditions. Regarding requirements R1, R2 and R3, to be consistent with the format of other NERC standards, the Criteria/Criterion listings should be made Parts of requirements R1, R2 and R3. Requirement R1 has the Planning Coordinator notifying the respective Generator Owner and Transmission Owner but a specific time period to complete the notification following the identification of an Element is not specified. This may appear as a gap in the process. The Planning Coordinator should have 30 days to notify the TO and GO. PRC-026 leaves out the use of transfer limits to correct for stable power swings. Transfer limits are an important tool for use in power system operations, and should be mentioned in a Rationale Box. Entities should not be exempted from the standard because of the linkage to Attachment A. Attachment A should not exclude Relay elements supervised by power swing blocking. Entities may install out of step blocking in order to be exempted from the standard. An entity may install Out of Step Blocking equipment without validating that it is set correctly because PRC-026 would not apply. Measure M3 is missing the word "meet". Measure M3 should read: M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which meet the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.
Group
Arizona Public Service Co
Janet Smith
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
The 30 days notification requirements for R2 and R3 is unnecessarily too stringent. We suggest 90 days.
Group
Puget Sound Energy
Eleanor Ewry

Yes
Yes
No
In general, we agree with the comments submitted by PSEG. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity's implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction – see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., "correct operations." We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase "system Disturbance" has same meaning as the NERC Glossary term for "Disturbance." In other words, "system" is unnecessary. In addition, a "Fault" was stated to be a "Disturbance." Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. • If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner's compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only "make work" for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 – Event Reporting – see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf . For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: • Automatic firm load shedding on p. 9 • Loss of firm load (preferably limited to non-weather related load loss) on p. 10 • System separation (islanding) on p.10 • Generation loss on p.10, • Complete loss of off-site power to a nuclear plant on p. 10, and • Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing. Without this notification, Events that happen outside of the Planning Coordinator's PC Area may not be properly identified by the affected PC. If this is not the intent of the standard, there needs to be a distinction made between whether relays should be evaluated against local disturbances (disturbances within the PC Area) and system-wide disturbances that would be communicated throughout the region.
Yes
No
It should be recognized in the requirement that the appropriate response to a trip due to a stable power swing might be to take no action. The requirement should be amended to allow the Element owner to make a declaration that corrective action would not improve BES reliability, therefore action will not be taken, consistent with PRC-004-3, R5.
Yes

Yes
No
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
John Seelke
Public Service Enterprise Group
Yes
No
The Planning Coordinator should be obligated in R1 to provide system impedance data as described in the Attachment B Criteria for each Element identified in R1 to the TO or GO that owns the Element. PCs maintain the models that contain this data, and having them provide it will result in consistency for relays set within the PC's area.
This question is a duplicate of the prior question. The response below answers Q3 in the unofficial comment form. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity's implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction – see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., "correct operations." We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase "system Disturbance" has same meaning as the NERC Glossary term for "Disturbance."

In other words, “system” is unnecessary. In addition, a “Fault” was stated to be a “Disturbance.” Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. • If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner’s compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only “make work” for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 – Event Reporting – see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf . For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: • Automatic firm load shedding on p. 9 • Loss of firm load (preferably limited to non-weather related load loss) on p. 10 • System separation (islanding) on p.10 • Generation loss on p.10, • Complete loss of off-site power to a nuclear plant on p. 10, and • Transmission loss on p.11 To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing.
Yes
No
The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5.
Yes
No
Individual
Oliver Burke
Entergy Services, Inc.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Based on the information contained in the SPCS Power Swing Report Dated August 2013, there is insufficient evidence in the historical study case identified, to warrant implementation of the proposed PRC-026-1 standard.

Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
No
Requirements R2 and R3 appear to require the reporting of trips due to UNSTABLE power swings. Seminole feels that a better mechanism for collecting information on unstable power swings is through NERC Section 1600 data requests, not via a Standard. Requirements R2 and R3 utilize the term “identifying.” Can the SDT add language in the application guidelines that clarifies that “identifying” means “making a determination,” as the term identifying is somewhat unclear to Seminole.
No
Requirement R5 requires the development of a CAP. Seminole requests that the ability to submit a notification to the Entity’s RRO, stating why a CAP cannot or should not be implemented, be added to R5. Seminole reasons that there may be instances where a CAP is not possible, somewhat akin to a TFE in the CIP-world. The SDT could make the CAP exception contingent on the RRO’s approval.
Individual
Kayleigh Wilkerson
Lincoln Electric System

Yes
Although aware of the forces driving the development of PRC-026-1, LES cannot support the standard. LES agrees with the statement in the NERC System Protection and Control Subcommittee's technical report titled "Protection System Response to Power Swings" that recommends against this standard. Reliability Standards PRC-023-3 and PRC-025-1 adequately ensure that load-responsive protective relays will not trip in response to stable power swings during non-Fault conditions. Additionally, as stated in this same report, consideration should be given to potential adverse impacts to Bulk Power System reliability as a result of the standard.
Individual
Mark Wilson
Independent Electricity System Operator
Yes
Yes
Yes
Yes
No
The scope of the proposed standard is directed at blocking the trip for stable power swings only. However, since existing distance schemes have the ability to trip for both stable and unstable swings, the standard can be interpreted as permitting a Transmission Owner to remove both trip abilities in order to comply with this standard. Removing the trip abilities for unstable power swings may have unintended consequences, such as preventing successful self-generating islands to form, making the restoration process much more difficult. In order to prevent any unintended consequence, we suggest that Requirement 5 is modified to have the Transmission Owner consult with the Planning Coordinator for whether out-of-step protection is needed, and if so, whether out of step tripping or power swing blocking should be applied: R5. Each Generator Owner and Transmission Owner shall, within 60 calendar days of an evaluation that identifies load-responsive protective relays that do not meet the PRC-026-1 – Attachment B Criteria pursuant to Requirement R4, develop a Corrective Action Plan (CAP) to modify the Protection System to meet the PRC-026-1 – Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping. (Each Generator Owner and Transmission Owner shall consult with their applicable Planning Coordinator if out of-step tripping should be applied at the terminal of the Element).
Yes
Yes
Individual
Amy Casuscelli
Xcel Energy
Yes
No
Criteria 1 uses the term "operating limit" and Criteria 2 uses the term "System Operating Limit;" although both are identified by the existence of angular stability constraints, thus seemingly defining the same type of operating constraint, i.e. operating limit. Xcel Energy would suggest either explaining the difference between the terms "operating limit" and "System Operating Limit", or eliminating the potentially duplicative criterion, since a "Generator" can be an "Element". In our

opinion, Requirement R1 is organized and written in a manner that makes interpretation difficult. Xcel Energy suggests that the drafting team consider re-organizing this requirement as suggested below. R1 could be split so that R1 requires the PC to perform the following at least once per year; R1.1 would require the PC to identify Elements meeting the bulleted list of criteria; R1.2 would require notification to the respective Generator Owner and Transmission owner of each Element identified in R1.1. Regardless of whether this Requirement R1 is re-organized as suggested above or not, we suggest the following rewrite of of Criteria 1 to minimize ambiguity. Criteria 1 can be split either at the “or” (as in “…addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements…”) or at the “and” (as in “…addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements…”). To provide additional clarity, Criteria 1 could be rewritten as: “Generator(s) and Elements Terminating at associated transmission stations where angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS).” These potential modifications would improve the readability of the requirement and provide for easier alignment with the associated Measures and VSLs. In addition, M1 could be rephrased to state “Each Planning Coordinator shall have dated evidence that demonstrates identification of Elements meeting the R1 criteria was performed on a calendar year basis and dated evidence that demonstrates the respective owners of the identified Elements were notified on a calendar year basis”. The existing M1 phrasing of “identification and respective notification of the Elements” reads as if the Elements are being notified rather than the owners of the Elements.
No
The Measures M2 & M3 do not match the R2 & R3 requirements. The measures only require that the TO and GO have evidence of the identification of elements, but do not require evidence of notification of identified Elements to the PC. The VSLs for R2 & R3 classify it as a Severe VSL if the TO or GO fails to identify an Element in accordance with R2 & R3. However, the way R2 & R3 are written, there is no requirement for the TO or GO to identify anything. As the requirements are currently written, the only requirement is that the PC is notified within 30 calendar days of identification of an Element meeting the criteria. If a TO or GO does not identify an Element, they can never be in violation of R2 or R3 as written. Further, if there is no requirement for identification of Elements meeting R2 or R3 criteria, it is not clear what the starting point is for determining the 30 day notification period. How is the official date of identification of an Element pursuant to R2 & R3 determined? And how is it officially documented for use in establishing PC notification due date in determining the severity of the violation? It is unclear what action the PC is going to take, upon notification of the identification of an Element meeting R2 & R3 criteria, beyond adding the Element to the R1 list for future years that will be provided to the TO and GO. If that is the only resulting action, the 30 day notification of the PC or the <10 day overdue Lower VSL, <20 day overdue Moderate VSL, <30 day overdue High VSL or >30 day overdue Severe VSL do not seem to align. R4 directs the TO and GO to analyze the Elements within 12 calendar months of identifying the Element pursuant to R2 or R3. If the only action taken by the PC is to add the Element to the R1 list for future years, is would seem to be just as effective from a reliability perspective to give the TO and GO up to the next calendar year to notify the PC about R2 7 R3 identified elements and to align the R2 & R3 VSL notification timeframes with those allowed for the PC to TO/GO notifications in R1.
No
We are generally supportive of the revisions to R4 but offer the following observation. We believe that the way R4 is currently written, an Entity would be allowed to not evaluate an Element’s load responsive relays if they had been evaluated in the past three calendar years even if the Element was identified within the last 12 calendar months per R2 or R3 to have tripped in response to a stable power swing. For example, if an element tripped in January 2015 due to a stable power swing, the R4 analysis is performed and corrective action taken per R5 and R6. If the device trips again in 2016 due to a stable power swing, it would appear that there was a problem with the 2015 analysis. But the way R4 is written, the entity would be exempt from performing any analysis or taking any further action until 2018. We do not believe this is the drafting team’s intent.
Yes
The VSLs for R4 and R5 seem inconsistent. Entities are given 12 calendar months to perform an analysis with VSLs of increasing severity for being <30, <60, <90, and > 90 days past due. They are given 60 days to develop a CAP following completion of an evaluation that determines the need for a protection system modification to meet PRC-026-1 Attachment B criteria, and with an R5 VSL of increasing severity for being <10, <20, <30 or >30 days past due in the development of a CAP.

Given the 12 month leeway on the completion of analysis following identification of the Element and the only 60 day leeway on CAP development, why would an entity sign off an R4 analysis as complete for an element requiring a protection system modification prior to the 12 month deadline, essentially starting the 60 day clock on the CAP development R5 requirement? We recommend that all R4 analysis completion and R5 CAP development timeframes be based on the calendar months from the original date of identification of the susceptible Element and that the same <30 day, <60 day, <90 day and >90 day increments be used both R4 and R5 VSLs. This approach would eliminate any potential benefit from delaying the officially acknowledged date of completion of the R4 analysis and not have any effect on the final R5 max CAP development timeframe (ie. months since initial Element identification) allowable by the standard.
No
In the Application Guidelines, Criteria 1 uses the term “operating limit” and Criteria 2 uses the term “System Operating Limit” although both are identified by the existence of angular stability constraints, seemingly defining the same type of operating constraint, i.e. operating limit. Xcel Energy would suggest either explaining the difference between the terms “operating limit” and “System Operating Limit”, or eliminating the potentially duplicative criterion, since a “Generator” can be an “Element”. The lens calculation tool is not validated or authorized for use. Due to the hypothetical nature of the calculations, a standardized tool should be provided so that industry can achieve consistent results. There is no requirement that the TO provide the System Equivalent to the GO. This Standard should provide communication requirements between the GO and TO, similar to the MOD series standards effective inn 2014. While this may not be necessary due to the typically amenable working relationships in a vertically integrated utility, it may be required in areas that are served by several companies.
Yes
We believe there is insufficient technical basis to make this a viable standard for industry to properly apply, and provide the following comments for consideration: We concur with the NERC concern noted in #133 of FERC order 733 that careful study and analysis of the relationship between stable power swings and protective relays is needed and consultation with IEEE and other organizations should be completed before developing a Reliability Standard addressing stable power swings. The need basis for this standard is 2003 blackout event data. Since that time, many improvements to protection systems have occurred, voltage control and frequency control requirements have either been implemented, are on a staged implementation plan, or are planned in the immediate future. The need basis data set has changed and should be based on current information, rather than past uncontrolled system reliability program data. Many improvements over the last 11 years have changed the probability of this particular need occurring, including: • Use of Generator AVR and PSS systems • Improved facility equipment ratings • Automatic voltage and frequency ride-through standards for wind turbines • Coordinated protection system settings amongst all players • Better system modeling and transmission planning These concerns would be addressed by a carefully planned study as described. We are aware of FERC’s concerns around undesirable operations due to stable power swings, per Orders 733, 733A and 733B. The directive in #150 states “…we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.” We are also aware that this requirement was reinforced on September 4th, in the applicable FERC staff meeting. Due to the real or perceived urgency in completing this standard, we have offered some proposed wording intended to expedite the acceptance of the regulation. As written, we believe this draft holds potential opportunities for improvements towards readability and cohesiveness.
Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
No
Requirement R1 provides additional clarity of which Elements (including transformers, generators) are included in a notification by the Transmission Planner. In light of the fact that the purpose of this

standard is “To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions” which is in agreement with the FERC Order 733 (Section 150 of the FERC Order: “requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement”), it is an unnecessary extension of the Order to include unstable power swings. The Standard Drafting Team stated “The phase “stable or unstable” was inserted to clarify that both are applicable to power swings because the goal of the standard is to identify Elements susceptible to either” overreaches the FERC Order. Luminant recommends that unstable power swings be removed. Additionally, R1 should be modified so that notifications are not required for elements and relays that were previously identified and are currently in a Corrective Action Plan. The Planning Assessment referenced in R1, Criteria 4 should be limited to the contingencies in TPL-001-0.1 “Table 1 Transmission System Standards – Normal and Emergency Conditions” Category A, B, C and D to focus the power swing evaluations and corrective action development on activities that support the reliability of the BES.
Yes
No
Luminant agrees that Criteria A (Attachment B) provides a method for determining a relay setting to minimize unnecessary trips due to a stable power swing; however, Luminant recommends that the generation application section include an out-of-step relay example for stable power swings. Luminant also recommends removal of unstable power swings from the requirement based on the same comments in question 2.
Yes
No
Luminant recommends that in the Generator Application section, an example of a generator out-of-step relay application for stable power swings should be provided.
Yes
No
Individual
Barbara Kedrowski
Wisconsin Electric
Yes
Yes
No
: We take issue with this requirement. First, it will be difficult or impossible for the Generator Owner (GO) to comply with. The requirement in R3 is to notify the Planning Coordinator of an Element that trips due to a stable or unstable power swing during an actual system Disturbance due to the operation of its load-responsive protective relays. Without dynamic disturbance recording (DDR), it may not be possible to determine that the relay tripped due to a power swing. The GO is not required to have (DDR) capability for every generator. Note that DDR will only be required by the future PRC-002 standard for a subset of generators, not all of them. The most that a GO may be able to do is to say that a generator relay may have operated for a power swing, especially when the Generator Owner does not own or operate the connected transmission system. Second, if an unstable power swing passes through the generator or generator step-up transformer, the generator SHOULD trip in order to prevent or limit possible damage. The generator out-of-step relay is used for this purpose, and it does not appear that this standard will allow the necessary settings on the Device 78 element to properly protect the generator. Common industry settings for the 78 out-of-step function do not appear to be possible based on the Application Guidelines in the draft standard. For these reasons, we believe that this requirement should be removed. If it is retained, then the

scope of the applicability to generators should be limited to those generators where DDR will be required per the future PRC-002.
No
The limitations imposed in the Application Guidelines will not allow a Generator Owner to set an out-of-step relay to properly protect the generator, using commonly applied settings such as for single blinder schemes, and possibly other out-of-step schemes. The settings must be able to detect a power swing in the generator or GSU transformer, which appears to violate the setting limits as in the example of Figure 20.
No
Similar to PRC-004-3 R5, the entity should be allowed to explain in a declaration why corrective actions would not improve BES reliability and that no further corrective actions will be taken. For overall BES reliability, It must be left to the equipment Owners to determine when relay settings which do not meet the Application Guidelines must still be used for proper equipment protection.
No
For generators, the Application Guidelines make reference to using the generator transient reactance X'd. However, Tables 15 and 16 show the sub-transient reactance X''d in the calculations. This appears to be a discrepancy. See also Question 3 above.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
Simplifying the requirement to a single entity clarified the responsibilities.
Yes
Simplifying the requirement to a single entity clarified the responsibilities.
Yes
Since the criteria is not completely the same for the TO and GO, spliting the previous R2 into a new R2 and new R3 was a good move.
No
Is the Criteria a single page (page 17) or is it pages 17-73? The text in the rationale should be included in the Criteria paragraph so that there is no doubt what the evaluation is supposed to demonstrate. The previous draft (R3) presentation of the demonstration, CAP development, and PC/TP/RC communication was easier to understand just what was expected of the GO and TO.
No
Already discuss in Q4 comment - the requirement to develop a CAP was clear either way. The addition of the 60 day due date added more detail.
No
The calculations, requiring the extent of material provided in the application guide to explain, appear to be quite complex and difficult. Is the SDT open to considering an alternative method of evaluation? It is proposed that GO or TO give relay settings to the entity with the transient analysis modeling tool (TP/PC), and that entity determine if the GO/TO relay settings need to be modified based on the power swing characteristics and simulation results for the area being reviewed.
Yes
Yes
Comments for Application Guidelines 1. Page 1 – "The development of this standard implements the majority of the approaches suggested by the report." 2. Page 6 – "The standard does not included any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs." 3. Page 8 – "In order to establish a time delay that strikes a

line between a high-risk…" What is meant by "strikes"? 4. Page 8 – "For a relay impedance characteristic that has the swing entering and leaving beginning at 90 degrees with a termination at 120 degrees before exiting the zone…" "Add degrees" 5. Page 9 – Title of "Application to Transmission Elements", should be "Application Specific to Criteria A". 6. Page 9 – reference Fig 13 and 14 when discussing "infeed effect" 7. Figure 3 – Update text box "Constant Angle…Boundary (120 degrees)". 8. Table 2 through 7 – Do not need to calculate each point, does not provide added value to the document. 9. There are many tables and figures not referenced in the written portion of the document which makes the guideline difficult to read and follow. This is the case for Figure 13, 14, 15, and almost all the tables.
Individual
Bill Fowler
City of Tallahassee
Yes
No
The Planning Coordinator should be obligated in R1 to provide system impedance data as described in the Attachment B Criteria for each Element identified in R1 to the TO or GO that owns the Element. PCs maintain the models that contain this data, and having them provide it will result in consistency for relays set within the PC's area.
No
R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity's implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction – see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., "correct operations." We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase "system Disturbance" has same meaning as the NERC Glossary term for "Disturbance." In other words, "system" is unnecessary. In addition, a "Fault" was stated to be a "Disturbance." Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. • If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner's compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only "make work" for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 – Event Reporting – see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf . For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: • Automatic firm load shedding on p. 9 • Loss of firm load (preferably limited to non-weather related load loss) on p. 10 • System separation (islanding) on p.10 • Generation loss on p.10, • Complete loss of off-site power to a nuclear plant on p. 10, and • Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This

would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing.
Yes
No
The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5
Yes
This standard will cause a large increase in workload for entities with a small trade off of system reliability.
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Yes
AECI agrees with SPP Commments
No
AECI agrees with SPP Commments
No
AECI agrees with SPP Commments
No
AECI agrees with SPP Commments
No
AECI agrees with SPP Commments
AECI agrees with SPP Commments
Individual
Jonathan Meyer
Idaho Power
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
The 30 day time requirement for notification of swing tripping events in R2 and R3 seems a little short. I think 45 to 60 days would be more appropriate.

Individual
John Pearson/Matt Goldberg
ISO New England
No
While we agree with the removal of the Reliability Coordinator and Transmission Planner, we don't believe that entities should be exempted from the standard by the linkage to Attachment A. Attachment A excludes Relay elements supervised by power swing blocking. An entity could just install Out of Step Blocking equipment with nothing to ensure that it is set correctly and the standard would not apply through the exclusion in Attachment A.
No
R1 should be changed to read: R1. Each Planning Coordinator shall, for all design criteria events at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any:
No
Although splitting the requirement into two adds clarity, what was the underlying uncertainty that this is intended to address? R4 continues to be a combined TO/GO requirement that was not split. We ask whether the same uncertainty exists for R4 (previously R3) and should it also be split?
Yes
No
For R5, Generator and Transmission Owners need more time develop a Corrective Action Plan. The requirement should provide at least 180 days to develop the Corrective Action Plan. This will allow for a more complete and thoughtful response than can be obtained in 60 days. Also under R5, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. Right now, the requirement is open ended without the provision of Corrective Action Plan information.
Yes
No
Twelve months is not adequate to prepare for this standard as written. The drafting team should change the implementation plan to twenty four months.
Yes
PRC-026 leaves out the use of transfer limits to correct for stable power swings. Transfer limits are an important tool for use in power system operations. Furthermore, Attachment A should not exclude Relay elements supervised by power swing blocking. Entities might simply install out of step blocking in order to be effectively exempted from the standard. An entity could just install Out of Step Blocking equipment with nothing to ensure that it is set correctly and the standard would not apply through the exclusion in Attachment A. This will not improve power system reliability.
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
No Comments
No
We agree with the Public Service Electric and Gas Company comments. Additional Comments: 1.) Please define a "transmission switching station," is that the same thing as a sub-station? 2.) Please clarify "angular" stability limit versus just a stability limit. 3.) How are people modeling the relay settings for R1.4? Our facility ratings take into account relay setting limitations and the facility ratings are used in the models. Is that sufficient modeling or is there some specific modeling expected for R1.4?
No

We agree with the Public Service Electric and Gas Company comments.
Yes
No
We agree with the Public Service Electric and Gas Company comments.
No Comments
Yes
No
Individual
Chris Scanlon
Exelon Companies
In the guidelines and technical basis section of the standard, a method for evaluating whether a distance element is susceptible or not is given. In the previous guidelines and technical basis, a simpler method of plotting the relay characteristic within the lens drawn at the 120 degree critical angle was also described. This method seems to have been removed from the current draft standard. This method works often for our protection schemes and requires no calculations (it is simpler and less work). The drafting team should consider putting this section back in the guidelines section to show that this method may also be used.
We agree with the drafting teams' decision that only those elements that trip in less than 15 cycles need to be evaluated for susceptibility to tripping during stable power swings. This follows from actual event experience that shows that the vast majority of relays that trip during power swings are zone 1s.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
A yearly notification is too often for this requirement since this information will rarely change. We suggest a yearly notification for any change from the previous year, with a five year notification of all identified Elements.
No
A trip during a stable power swing is a mis-operation and is covered in PRC-004. A trip during an unstable power swing is an intended result and not applicable to this standard. We suggest removing these two requirements.
No
Attachment A includes Out-of-step tripping. This condition is an unstable power swing and should not be included in the standard. The standard should allow protection relays and philosophies to protect the equipment first and foremost. The requirement not to trip during a stable power swing should be reviewed and considered, but not mandatory if deemed that protection will be sacrificed.
No
Out-of-step tripping and tripping for unstable power swings are intended results. Corrective Action Plans are not needed for these events.

No
The graphs seem not to match the calculations.
Yes
No
Group
Duke Energy
Colby Bellville
Yes
Yes
Yes
Yes
Yes
Duke Energy agrees that this an improvement from the previous draft. However, we seek guidance or clarification on the boundaries between PRC-026-1 and PRC-004-3. When Misoperations occur due to a stable power swing, a CAP is required to be developed pursuant to R5 of PRC-004-3. Would the evaluation and, if needed, Corrective Action Plan from PRC-026-1 R4 through R6 be acceptable as use for the CAP required in PRC-004-3 R5?
Yes
Duke Energy agrees in part with the revisions made by the SDT on this project. However, due to the amount of technical information provided in the Application and Guidelines portion of this standard, more time is needed for our SME(s) to thoroughly review this section before submitting an “Affirmative” vote.
Individual
David Thorne
Pepco Holdings Inc.
Yes
Yes
No
The 30 day time line provided for Requirement R2 in the standard to determine if an element operated due to either of the Criteria provided seems aggressive. The shortest amount of time we have to determine if a protective relaying scheme mis-operated under current quarterly reporting requirements for PRC-004 is 60 days. It would make sense if the timeline for this standard was adjusted to match. In addition, the requirement as written does not seem to differentiate if this level of analysis is required for the operation of all in-scope protective relaying schemes or just those that were determined to mis-operated. Requiring this level of study for all in-scope protective relaying schemes would seem to provide a tremendous compliance burden to the Transmission Owners.
Yes
The requirement as written in the latest draft version of the standard is clear on what actions must be taken. The 12 month timeline is reasonable.
Yes

The requirement as written in the latest draft version of the standard is clear on what actions must be taken. The 12 month timeline is reasonable.
Yes
Yes
The 36 month time line is sufficient
No
Individual
Glenn Pressler
CPS Energy
Yes
No
In general, support Luminant comments.
No
In general, support PSEG comments.
No
In general, support Luminant comments.
No
In general, support PSEG comments.
No
In general, support Luminant comments.
Yes
No
Group
ISO RTO Council Standards Review Committee
Greg Campoli
Yes
The Standards Review Committee (SRC) agrees with the removal of the Reliability Coordinator and Transmission Planner; however, there remains concern that that entities could be exempted from the standard by the linkage to Attachment A as it excludes Relay elements supervised by power swing blocking. The SRC, therefore, recommends that the SDT assure all Applicability is explicit in the Applicability Section of the standard and that exemptions or other criteria are not embedded in Attachment A. (note CAISO does not support the response to Question 1)
Yes
The SRC agrees that the revisions improved the clarity of Requirement R1. However, to ensure consistency with the other requirements within the Standard, the SDT recommends that Requirement R1 also be broken into two (2) requirements, one addressing identification and one addressing notification. Additionally, Requirement R1 should be changed to read: R1. Each Planning Coordinator shall, for all design criteria events at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any: Finally, the SRC recommends the following revision to Criterion 1 of Requirement R1 to streamline and ensure that the focus remains on Remedial Action Schemes: 1. Generator(s) where an angular stability constraint exists that is addressed by a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s).
No

The SRC notes that Requirements R2 and R3 are about notification if an element meeting specified criteria is identified. However, the measures are primarily focused on identification. Accordingly, the measures should be revised for consistency with the associated Requirements R2 and R3.
Yes
The SRC agrees that the revisions have provided clarity; however, notes the inconsistency within the standard regarding describing GO and TO requirements separately in Requirements R2 and R3.
No
We agree with consolidating the Corrective Action Plan obligations into Requirements R5 and R6. However, the SRC recommends that, for R5, Generator and Transmission Owners need more time to develop a thorough CAP that addresses identified issues with load-responsive protective relays. The requirement should provide at least 180 days to develop the Corrective Action Plan, which would will allow for a more complete and thoughtful response than can be obtained in 60 days. Also under R5, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. Right now, the requirement is open ended without the provision of Corrective Action Plan information.
No
The SRC notes that twelve (12) months is not adequate to prepare for this standard as written. Accordingly, it is recommended that the drafting team revise the implementation plan to allow twenty four months for implementation.
Yes
The SRC respectfully submits that the Purpose statement is unclear and inconsistent with the requirements in the standard. More specifically, the requirements often refer to stable and unstable power swings, but such are not addressed in the Purpose statement. This should be clarified. The following revision is proposed. To protect against tripping by load-responsive protective relays in response to stable and unstable power swings during non-Fault conditions. The SRC has concerns with potential inconsistency between the Purpose statement and the time horizons. Specifically, Requirements R2 and R3 have a time horizon defined as Long Term Planning while the Purpose of the standard is about expected / forecasted responses. However, the verbiage of Requirements R2 and R3 requires action by the responsible entities within 30 days, which implies that the Time Horizon should be, at most, the Operations Planning time frame. The SRC requests that the SDT to review these requirements to assure they are consistent with the purpose of the standard, the Time Horizons and any changes necessary to the Applicability section.
Group
Dominion
Connie Lowe
Yes
Yes
No
M3 seems to be missing the word ‘meet’; suggest M3 read as; M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which ‘meet’ the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets. Dominion agrees with the split of R2, however, elements could have their load-responsive protective relays operate prior to the formation of an island. In the Application Guide, a section should be included to better define methods used for boundary detection, if we are required to determine if the element was in-fact the boundary to an island. Otherwise, power swings could cause relays to operate without internal detection algorithms picking up the swing.
Yes
No

No date is given for CAP implementation. Is it acceptable to work the CAP in with projects regardless of project execution date? (3-7 years, if no project is in place at the specific location; is it acceptable to implement the CAP once a project arises?)
No
Under Criterion R4, ‘Exclusion of Time Based Load-Responsive Protective Relays,’ the calculations here are ambiguous. PRC-026-1 Attachment A explicitly states we are to evaluate protective functions listed with a delay of 15 cycles or less; however, there is small section outlining the need to calculate what sort of delays should be evaluated under different slip frequencies. Adding the ‘Exclusion of Time Based Load-Responsive Protective Relays’ section is counter-productive in its current context. Dominion suggests that the SDT revise the section to make it more understandable or remove it. No section discusses slip frequencies ranges. The WECC experiences 0.25-0.28 Hz north-south oscillations, ERCOT experiences 0.6 Hz north-south and 0.3 Hz east-west, Tennessee to Maine experiences 0.2 Hz oscillations, but Tennessee to Missouri experiences 0.7 Hz oscillations. Roughly 0.01 to 0.8 Hz oscillations are associated with wide area oscillations, but 3.0 to 10 Hz oscillations are associated with FACTS devices that may cause wide or local. What is the acceptable range of oscillations this standard is meant to cover?
Yes
If R4 is a precursor for R5 and R6, R4-R6 should be included in the 36 month implementation plan.
Yes
No part of the standard discusses reasonable slip frequencies that should be used to detect power swings. If we identify a relay that is susceptible to tripping for stable power swings (based on the mho impedance characteristic overlapping a portion of the lens), apply a form of power swing blocking, and then the relay operates again for a different frequency. Are we to go off the most recent analysis? Slip frequency is an integral part to power swing detection and determination between a swing and loading can be difficult. There should be some discussion about this topic in conjunction with loading. Should a section discuss the correlation with PRC-023-2 requirement R2? PRC-023-2 R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
Group
JEA
Tom McElhinney
Yes
Yes
Yes
Yes
No
This standard is not necessary and we agree with the analysis of the NERC SPCS that it may have unintended consequences which could decrease the reliability of the BES.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six

regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
No
The process of PCs annually performing an analysis and notifying TO/GOs of applicable Elements per R1, and of TO/GOs then evaluating these Elements per R4, should be clarified to note that where relays meeting criteria 1-3 of R1 are on the PC's list year after year a new evaluation is not required each time unless conditions have materially changed (threshold TBD by the SDT).
No
R4 should state that the 12-month clock for GOs begins when the TO provides the system impedance data necessary to perform studies, if the GO requests this information from the TO. Also, the reference to, "full calendar months," in R4 and Att. B should be changed to just, "calendar months," to prevent confusion.
No
: The deadline of 60 calendar days for development of a Corrective Action Plan should be changed to six months. Many GOs do not have Protection System design expertise, and the process of making a business case for the expenditure of hiring a contractor, getting this request approved, exploring alternatives, making a technical selection and again obtaining management approval can take far more than sixty days.
Individual
Jamison Cawley
Nebraska Public Power District (NPPD)
Yes
No
The PSRPS Recommendations Section states that the SPCS determined a Reliability Standard is not needed.
No
Both R2 and R3 requirements appear to take a "wait and see" approach rather than a proactive approach. This doesn't seem practical when maintaining the reliable operation of the BES. We recommend elimination of both R2 and R3. Additionally, R2 states that the TO would need to identify "an Element that forms the boundary of an island during an actual system Disturbance due to the operation of its load-responsive protective relays." This type of event would be very complex and would likely include many contingencies. Thus the statement seems too general and all-encompassing. We feel this reliability function might be better served by the Planning Coordinator(s) or Reliability Entity facilitating an event analysis where better decisions and recommendations can be made, given their wide-area view and awareness of reliability issues. If a relay did trip on OOS for a stable power swing, the likelihood of it being part of a larger event or a misoperation is high. If it were a misoperation, it would then be addressed in another standard or event analysis process. As noted above it seems R2 and R3 are better served by existing processes or standards.
Yes
Yes
We agree that separation of the CAP requirement is an improvement; however, we feel there should be a caveat to this requirement. The standard as written could result in reduced sensitivity of fault detection settings, which would interfere with "maintaining dependable fault detection". We believe there should be an option to maintain our ability to operate the BES in a reliable manner and still remain in compliance with R5. This requirement seems like double-jeopardy.
Yes

Yes
Yes
We are curious why the PC is allowed 1 year to identify elements while the industry is allowed 30 days after a disturbance to identify elements. This does not seem practical in comparison with the timelines used with other reporting requirements. For example, PRC-004 has quarterly submissions with 2 additional months after the quarter end; the new PRC-004-3 allows 120 days just to identify if an operation was a misoperation, root cause determination is not included in that timeframe. In fact, PRC-004-3 includes no set timeline to determine cause, simply a requirement to actively investigate by indicating active investigation every two calendar quarters until a cause is determined or no cause can be found. An out-of-step analysis is more complex, so it would be logical to allow longer time horizons for this type of investigation and identification, perhaps no less than an annual interval which would match the PC. Additional clarification on two items is requested: 1) If a relay has out of step tripping and blocking enabled, does this mean it is excluded from the standard? 2) If a relay has out of step blocking enabled, does this mean it is excluded from the standard? In addition to these comments, we support the comments provided by SPP.
Individual
John Merrell
Tacoma Power
Yes
Yes
Yes
Yes
Yes
No
In the Application Guidelines, in the discussion of Figure 11, suggest changing "...thus allowing the zone 2 element to meet PRC-026-1 – Attachment B, Criteria A" to something like the following: "...thus allowing the zone 2 element to meet PRC-026-1 – Attachment B, Criterion A. However, including the transfer impedance in the calculation of the lens characteristic is not compliant with Requirement R4." Similarly, update the Figure 11 caption to indicate that the calculation is not compliant with Requirement R4. In the Application Guidelines, in the discussion of Requirement R5, the statement "that all actions associated with any Corrective Action Plan (CAP) developed in the previous requirement [Requirement R4]..." is incorrect. Requirement R4 does not have anything to do with a CAP.
Yes
Yes
For Requirement R2, consider defining 'island' or adding a footnote clarifying the intent of the word. This requirement should not apply to portions of the system containing both generation and load that become isolated from the BES but that are not intended to operate apart from the BES. For example, perhaps there are parallel lines that interconnect one or more remote generation plants and some load to the rest of the system. It is doubtful that the drafting team intended to include these types of scenarios as 'islands'. Should POTT and DCB schemes be specifically called out in Attachment A as being applicable to PRC-026-1? Attachment B Criterion B may yield current that is above the phase time overcurrent pickup but, at this level of current, the phase time overcurrent element may take longer than 15 cycles to operate. Therefore, the approach in Attachment B Criterion B is potentially conservative. The Response to Issues and Directives still mentions that

“...the proposed standard does require that an Element that was part of a boundary that formed an island since January 1, 2003 be identified as an that is within the scope of the proposed standard.”
Individual
David Jendras
Ameren
Yes
Yes
No
Ameren adopts the following comment submitted by PSEG. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity’s implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction – see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., “correct operations.” We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase “system Disturbance” has same meaning as the NERC Glossary term for “Disturbance.” In other words, “system” is unnecessary. In addition, a “Fault” was stated to be a “Disturbance.” Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. • If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner’s compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only “make work” for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 – Event Reporting – see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf . For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: • Automatic firm load shedding on p. 9 • Loss of firm load (preferably limited to non-weather related load loss) on p. 10 • System separation (islanding) on p.10 • Generation loss on p.10, • Complete loss of off-site power to a nuclear plant on p. 10, and • Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing.
Yes
No
Ameren adopts the following comment submitted by PSEG. The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5.

Yes
Yes
Yes
We appreciate the SDT's significant improvements in this draft 2. Our response to question 3 above captures our primary reason for voting negative.
Individual
Joe O'Brien
NIPSCO
No
We would prefer that the 12 month implementation plan for R1-R3, R5, R6 be set to 24 months; this is based on the related burden of implementing PRC-025-1.
Individual
Michael Moltane
ITC
Yes
Yes
Yes
Yes
No
A "no CAP declaration" should be added to R5. This option is necessary when enabling power swing blocking affects the BES reliability. An example is for a Slow Trip – During Fault, in which the high-speed protection scheme has been identified to meet the dynamic stability performance requirements of the TPL standards. As ITC stated in Draft 1, we are concerned about load/swings with subsequent phase faults which result in time-delayed tripping when power swing blocking is enabled.
No
The R2 example of an island forming is insufficient. Suppose a line includes tapped load and a tapped generator, does this form an island if the line ends trip for a phase fault? R2 Criteria 2 does not exclude this example, therefore it should be discussed in Application Guidelines and Technical Basis.
Yes
Yes
In R2, add reference to Attachment A when describing the load-responsive protective relays. R2 Criteria 2 adds no value and should be removed. All Elements which trip due to swings will be captured under Criteria 1. Criteria 2 only includes islands formed due to phase faults and adds no value. If you intend to capture boundaries of all islands formed, then remove the "due to the

operation of its load-responsive protective relays” qualifier. If you intend to capture boundaries of all islands formed due to protective relay operations, then remove the “load-responsive” qualifier. Application Guidelines, page 63, Application to Generation Elements, change the language to include generator relays, if they are set based on equipment permissible overload capability. “Load-responsive protective relays such as time over-current, voltage controlled time-overcurrent or voltage-restrained time-overcurrent relays are excluded from this standard [if] they are set based on equipment permissible overload capability.” Application Guidelines, page 72, the first paragraph under Requirement R5 is more appropriate under Requirement R6.
Individual
Karin Schweitzer
Texas Reliability Entity
No
Texas Reliability Entity, Inc. (Texas RE) has concerns regarding the removal of the Reliability Coordinator (RC) from the applicability, particularly for Criteria 1 and 2 of R1. The time horizons that the Planning Coordinator (PC) and RC evaluate are different, with the Planning horizon being > 1 year and the Operations horizon being real-time to < 1 year. When the SDT removed the RC from the applicability, the Operations Planning time horizon was also removed; however, there is still language within Criteria 1 and 2 of R1 addressing angular stability constraints as monitored as part of a System Operating Limit identified in operating studies. Operating studies are not typically conducted by the PC but are conducted by the RC. Based on the language in the Criteria, it is unclear to Texas RE whether the intent of the standard is to only identify elements at risk in the Long-term Planning horizon or to identify elements at risk in both the Operations horizon and the Long-term Planning horizon. Texas RE requests clarification on this issue from the SDT. Please also see our comments to Questions 2 and 3 regarding time horizon concerns.
Yes
While Texas RE agrees with the approach of using criteria from the PSRPS technical document, we have concerns about the stated time horizon. Requirement R1 Criterion 2 states that the PC should include elements identified in operating studies, but the time horizon for this requirement is Long-term Planning. Texas RE suggests that either the Operations Planning time horizon needs to be added to this requirement or the reference to operating studies needs to be removed, whichever is in line with the intent of the SDT.
Yes
While Texas RE agrees with splitting the previous Requirement R2 into Requirement R2 for the Transmission Owner (TO) and Requirement R3 for the Generator Owner (GO) for clarity, we have concerns regarding the stated time horizon. Requirement R2 states that the TO shall notify the PC within 30 calendar days of elements that trip due to an actual disturbance, but the time horizon for this requirement is Long-term Planning (which is a planning horizon of one year or longer.) Texas RE suggests that the time horizon should be Operations Planning. Requirement R3 states that the GO shall notify the PC within 30 calendar days of elements that trip due to an actual disturbance, but the time horizon for this requirement is Long-term Planning (which is a planning horizon of one year or longer.) Texas RE suggests that the time horizon should be Operations Planning.
Yes
No comments.
Yes
No comments.
Yes
No comments.
Yes
No comments.
Yes
Texas RE suggests that the PRC-026-1 SDT refer this standard to the Project 2014-01 SDT (if not done already) for consideration regarding the applicability of BES generators to include dispersed generation resources so the requirements of the standard pertain primarily to the point of connection where the resources aggregate to 75 MVA or more, and not to the individual resources.

Since this is a new standard it is not currently included in “Appendix B: List of Standards Recommended for Further Review” from the draft white paper entitled ”Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources.”
Group
Florida Municipal Power Agency
Carol Chinn
No
FMPA is comfortable with the removal of the Reliability Coordinator and Transmission Planner, subject to comments we are making on R2, R3 and in response to question 8.
Yes
No
Requirements R2 and R3 need further clarification. FMPA agrees that splitting the Requirement was beneficial. However, FMPA finds the following issues left requiring resolution, which point to the need to better coordinate this standard with PRC-004: 1. The language is crafted as if a typical TO or GO would easily be able to determine that an element tripped due to a power swing. This only makes sense for large vertically integrated utilities in which staff with a variety of knowledge bases and skill sets may be working together. In reality, for smaller utilities that may be only a TO/DP or GO, this determination will require some involvement from a TP, PC, TOP, or RC, with staff that have a) access to real time information, event records, and other information beyond what any single TO or GO may have and b) an understanding of the expected regional stability performance which TO/GO staff may not have. Realistically it should only be presumed the TO or GO staff will be able to conclude that their relays did not trip for a fault. 2. The standard sets a 30 day clock which starts with a piece of information that isn’t required or driven from anywhere – namely, the point in time at which at TO or GO discovers that any relay operated (either correctly or incorrectly) due to a power swing. Since there is currently no place where it is required that correct/proper relay operation be documented, it is not clear what sort of documentation the TO/GO will have and what process, performed by what staff, would drive the TO/GO to “initially discover” that the relay operated due to a power swing. The point being- in a normal PRC-004 investigation, at such time as it is discovered that a relay properly operated, there is no requirement for any formal report, on any formal schedule, to include that information. At what point does the “official” starting point of this 30 day clock occur? This points to the need for further/better coordination with PRC-004.
No
See comments in response to Question 8 related to Applicability and responsibility for various requirements.
No
FMPA agrees with the separation of R5 and R6. However, R5 pre-supposes and furthermore directs that the only acceptable Corrective Action Plan is one which involves modifying the Protection System. There are a number of other ways to improve stability performance which are therefore ruled out. In fact, improving the performance to, and reducing the severity of power swings that result from a given event should be a preferential solution as it has a much wider impact on the stability and the reliability of the system. It may be true that modifications to microprocessor relay settings or even replacement of relays might be the least cost or the fastest and simplest solution, that in no way should dictate that the standard should mandate this be the only corrective action employed.
No
FMPA commends the drafting team on the amount of material that has been developed to support the Application of this standard. The various examples used in the Application Guide are generally good example scenarios. However, the focus of the Guide seems to be more on repetitive demonstration of basic equations and less on the SDT’s expected interpretation of various scenarios. One full sample of all the calculations in one scenario is all that is required. Each time the equations are repeated it takes roughly 11 pages. In general there are a lot of pages of basic equations and very little “guidance” within the examples. Furthermore, the examples seem to have been developed to make a supporting case for the Criteria of Attachment B but there is no true discussion of how

these examples should be interpreted to support the Criteria. An easy example of this is Table 10, where the impact of the system transfer impedance on the lens characteristic is tabulated, but there is no use of that data to explain why all transfer impedances, no matter what the magnitude, should be completely ignored. The data is there, but the expectations regarding interpretation of the data are more important, and these are missing. A couple of additional issues that FMPA believes should be cleaned up. • The first full paragraph of Page 28 of the Application Guidelines describes the modeling of generator reactances in stability models, but there is no segue regarding why this information was presented. Please clarify that the intent of the paragraph is to make it clear that the reactances that are used by TP's/PCs (unsaturated reactances) may not be the same reactances as the ones that are being recommended for use in the application of the criteria (saturated reactances). • The Application Guide makes frequent reference to "pilot zone 2 element" in the figures. Strictly speaking the figures show an example of a "distance" or "impedance" mho relay characteristic curve. The term "pilot" refers colloquially in protection to a communication assisted scheme, which may be used in conjunction with a mho characteristic or may not. The use of this term introduces confusion because Attachment A specifically excludes "pilot wire relays", which are a specific sub-set of transmission relay that does not use a mho characteristic.
No
The Implementation Plan does not offer compelling evidence that the implementation date for R5 and R6, which are driven exclusively by R4, should be set at 12 months from approval while R4 is at 36 months from approval. Setting R5 and R6 earlier than R4 instead of allowing them to be parallel to R4 introduces circuitous logic as now the language of these Requirements appears to require R4 to be completed early…There does not appear to be any value in setting R5 and R6 at 12 months when there is nothing to measure compliance with them against – the implementation plan explains the 12 months to is to allow entities to develop "internal processes and procedures", but the Requirements do not require such procedures nor are these listed in the measures.
FMPA would like to commend the SDT for developing an overall process that is generally reasonable and does not, in our opinion, add an excessive compliance burden, since the number of identified circuits and generators should be small. However, we believe more work is required to make the concept the SDT has come up with successful. 1. First, as mentioned in earlier sections, the standard is in general written with the perspective of large vertically integrated utilities in mind, and does not consider the impact on non-vertically integrated TOs and GOs. As such, we believe there is further coordination that needs to be developed between this standard and PRC-004, that will a) facilitate communication between PCs, TPs, TOPs, the RC, and respective investigating TOs and GOs and b) will establish a clear timeline that can cleanly be audited for R2 and R3. As stated in our comments above on R2, the requirements for keeping records for "correct" relay operations are effectively non-existent in current standards. FMPA believes it makes sense for all "investigations" and associated records to occur within PRC-004 and then for "power swing" related activities to occur in PRC-026. Currently power swings are only discussed in PRC-004 as they relate to failure to trip or slow trip conditions (and not where operation for a power swing was correct). Furthermore there is presently no acknowledgment that GOs and TOs may need assistance and information from their TPs, PCs, associated TOP, or even RC. 2. The Applicability section refers to GO's and TO's that apply load responsive relays to Generators, Transformers, and Transmission Lines. FMPA sees three issues related to this. a. First, all language in the standard Requirements refers to Elements instead of Facilities – based on previous comments and the SDT's response to those comments, the standard Requirements should be referring to Facilities to draw focus to the BES distinction, which does not exist for Elements. b. Second, the identification of issues and tracking of issues from entity to entity is based on Elements. This works from the perspective of identification of risks to the system but falls short when it comes time to evaluate and modify the Protection Systems, because no Requirement refers back to the Owner of the Protection Systems applied on the Elements identified in R1. Instead, Requirements 2 and 3 are directed at the Owner of the Element itself which may or may not own the Protection System that is actually at risk of operating (or misoperating). The Requirements need to consider this relationship similar to PRC-004-3. c. Third, it is quite possible for protective relays applied on a substation bus section or on FACTS devices to be susceptible to power swings, and in fact, in cases of intentional system separation schemes, this may be an intentional design (e.g splitting a substation bus when one or a group of transmission lines exceed a measured condition). The Facilities section does not include such Elements. 3. FMPA is concerned the conditions under which Criteria A is being calculated may be excessively conservative. Item 3 of the

Criteria states “Saturated (transient or sub-transient) reactance is used for all machines.” Note the term “all”, which could be confusing if an entity is not considering the context. The documentation presented does not discuss terms such as “maximum generation dispatch” or any other term that would relate back to a realistic number of generators being in service. The requirement should be “all machines that are in service in short circuit model”, and in the Application Guide there should be some discussion on using maximum reasonable generation dispatches in short circuit cases. Similarly, but of less consequence, it is not clear that the Transfer Impedance should always be completely neglected. While this is certainly numerically convenient, FMPA wonders if this does not produce overly conservative results in cases of well-networked transmission. Would it not be more prudent to remove other transmission circuits which have significant transfer distribution factors relative to the line in question, and then re-calculate the transfer impedance, rather than assuming some exceedingly large number of transmission outages has occurred? This relates to the comment above that some discussion should be offered surrounding Table 10 in the Application Guide. 4. As written, the combination of Requirement R4 (which instructs the TO/GO to “evaluate” its relays against the “Criteria” in Attachment B) and the Criteria in Attachment B, make no definitive statements about what relays “meet” anything, or “are deficient and require corrective action plans” etc. Requirements and Criteria should be very clear and straight forward. The “Criteria” is really just a description. There is no information in the Requirement or in the Attachment that actually involves making a “judgment” which is the most important part of the definition of the term Criteria. FMPA is well aware of the intent of these two items and only wishes to point out that the intent is really only made clear in the Application Guidelines.
Group
DTE Electric Co.
Kathleen Black
Yes
Yes
Yes
No
R4 is clearer in general terms, however, the Criterion and related Guidelines and Technical Basis do not cover all the various relay scheme configurations that may apply. Since specific criteria must be evaluated, the concern is that relay scheme configurations not discussed may result in an incorrect evaluation.
Yes
No
While considerable discussion and examples have been provided, there are variations in relay types and schemes that are not specifically covered. Perhaps these variations could be submitted at some point for review and application guidance.
Yes
No comment
Yes
Will this Standard result in any conflicts with PRC-019 or PRC-025 while meeting protection goals in setting generator relays?
Individual
Muhammed Ali
Hydro One
Yes
Yes

Yes
Please refer to comments for 6.
Yes
Yes
This section now provides clarity for each of the requirements in the standard. However, for Requirement 4, the "Application Guidelines and Technical Basis," section does not provide direction on how to treat multi-terminal configurations (specifically 3-terminal). Providing guidance on how to approach multi-terminal configuation would be helpful.
Yes
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
Yes
Refer to 6.
Yes
No
This section now provides clarity for each of the requirements in the standard. However, for Requirement 4, the "Application Guidelines and Technical Basis," section does not provide direction on how to treat multi-terminal configurations (specifically 3-terminal). Providing guidance on how to approach multi-terminal configuation would be helpful.
Yes
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
Yes

No
Group
FirstEnergy Corp.
Richard Hoag
Yes
Yes
FirstEnergy suggests a slight modification to the wording of R1 Criteria 5 for clarity, as follows: “An Element reported by the Transmission Owner pursuant to Requirement R2 or Generator Owner pursuant to R3, unless …”.
Yes
Regarding R3, as a Generator Owner in a deregulated / competitive environment, we still have a concern about being held accountable for events for which we are unaware – power swings or Disturbances on the system (Criteria 1) – due to FERC Code of Conduct separation with the regulated system. We are not aware of system events. We realize, however, that R3 says, “… within 30 calendar days of identifying …”; the concern simply relates to the level of responsibility placed on the GO to “identify” tripping of load-responsive relays caused by “… a stable or unstable power swing during an actual system Disturbance …”.
No
Attachment B, Criteria A and B might be clearer to a Protection Design Engineer, but are not likely clear to typical compliance personnel.
Yes
Assuming a situation results in the need for a CAP, what is the purpose of stating that dependable fault detection (and out-of-step tripping if applied) shall be maintained while developing the CAP? Maintenance and testing of protection is covered in PRC-005, and any failure of existing protection is addressed by PRC-004. Why is there further need to address maintaining existing protection, and how is such a requirement measured in the context of PRC-026-1? Also, what is the anticipated mechanism for tracking and reporting progress on a CAP?
Yes
Yes
No
Individual
Dixie Wells
Lower Colorado River Authority
Yes
Yes
Yes
The splitting of requirement for GO and TO was good. It would be more clear if R2&R3 can directly refer to the protective elements being addressed in Attachment A are the elements to look into when power swings (stable/unstable) occurs. Also, listing some particular in events that power swings would happen can be helpful.
No
see comments for R4 under application guidelines.
No

R5(part of the previously R3), missed the alternative options in previously R3 which allows entities owner to obtain agreement from planning coordinator, if a dependable fault detection or out of step tripping cannot be achieved. R5 in application guideline asks to "develop" and "complete" the CAP, while R5 in the standard only ask to "develop" within 60 cal day time period. It's ambiguous with R6 in the standard which asks to "implement" the CAP without any specific time period . And i assume this is to allow the "implementation" to be occur during next available plant outage.
No
see comments for application guidelines. It would be helpful to include out of step examples for the GO and TO.
Yes
No
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Yes
Yes
Yes
Yes
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Yes
The addition of criteria 5 seems circular in that the PC is notifying the GO or TO about Elements they already know about. If the PC's analysis applying criteria 1-4 does not identify these Elements initially, why should the same PC criteria be entrusted to determine that "the Element is no longer susceptible to power swings"?
Yes
No
While an improvement over the previous draft, we believe the time interval for consideration of previous evaluations should be extended to the prior five calendar years. We also would prefer to see more flexibility in the standard to allow entities to use their preferred methods (not strictly adhering to Attachment B criteria) for determining if a line is likely to trip during a stable power swing.
Yes

Group
Santee Cooper
S. Tom Abrams
No
There seems to be some overlap between PRC-004 and R2 and R3 of this standard (PRC-026). For compliance with PRC-004, entities have to analyze all operations in order to prove that all misoperations are identified. To identify an Element that (according to R2 and R3 of PRC-026) “trips due to a stable or unstable power swing during an actual system Disturbance due to the operation of its load-responsive protective relays,” a similar proof could be required, that all trips of load responsive relays were evaluated under a criteria to rule out operation due to stable or unstable power swings. The listed Rationale for R2 gives mention to the review of relay tripping is addressed in other NERC Reliability Standards, so there seems to be a nod given to PRC-004, but it should be clearer as to the interrelationship between these standards. Significant confusion could result if the interrelationship or dividing line (whichever is more appropriate) between these two standards is defined further. Will compliance with R2 and R3 of PRC-026 only involve having the data for the operations determined to be caused by power swings, or will it require data that entities provide documentation of the evaluation each operation for power swing implications?
Individual
Jason Snodgrass
Georgia Transmission Corporation
Yes
No
Recommend further clarity and a revision to R1 criteria 1 such as: From this: Generator(s) where an angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s). To this: Generator(s) and those interconnecting Elements terminating at the transmission switching station associated with the generator(s), where an angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS).
Yes
Yes
Yes
Yes
Group
SPP Standards Review Group

Shannon V. Mickens
Yes
Thank you for removing the Reliability Coordinator function. The Reliability Coordinator has no place in this standard.
No
In light of the fact that the purpose of this standard is “To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions” which is in agreement with the FERC Order 733 (Section 150 of the FERC Order: “requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement”), it is an unnecessary extension of the Order to include unstable power swings. The Standard Drafting Team stated “The phase “stable or unstable” was inserted to clarify that both are applicable to power swings because the goal of the standard is to identify Elements susceptible to either” overreaches the FERC Order. We recommend that the term ‘Unstable Power Swing’ be removed from the standard.
No
What is the difference between ’12 full calendar months’ and ‘12-calendar months’? Delete the ‘full’ in Requirement R4. In the 3rd line of Requirement R4, change ‘Requirement’ to ‘Requirements’. Refer to our comments in Question #2 as to why we don’t agree with the revisions.
No
Insert a ‘to’ between ‘pursuant’ and Criterion’ in the 3rd line up from the bottom of the paragraph on Criterion 1. In the 9th line in the 1st paragraph under Criterion 4, capitalize ‘Criterion’. In Figures 1 and 2, change ‘Criterion five’ to ‘Criterion 5’. In the 7th line of the paragraph following Figures 1 and 2, change ‘included’ to ‘include’. In the 8th line of the paragraph under Requirement R4, delete ‘full’ and hyphenate ’12-calendar’. In the 5th line of the 2nd paragraph under Exclusion of Time Based Load-Responsive Protective Relays, insert ‘degrees’ between ‘120’ and ‘before’. In the 3rd line of the paragraph immediately following Table 1, capitalize ‘Zone’. In the 15th line of the same paragraph, delete the same phrase in the parenthetical. In the 4th line of the paragraph following Equation (3), replace ‘plus and minus’ with ‘±’. Capitalize ‘Zone 2’ in the captions of Figures 10, 11, 12, and 15. In that same paragraph, capitalize ‘Zone 2’. In the last line of the 2nd paragraph under Application to Generation Elements, replace ‘Requirement’ with ‘Requirements’. Capitalize ‘Zone 2’ in the 1st line of Example R5a. Capitalize ‘Zone 2’ in the 1st line of Example R5c.
No
We have a concern that the Implementation Plan doesn’t reflect the changes mentioned by the drafting team in their response to our comments on Question 4 in the previous posting. That response states ‘The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element… where the evaluation has not been performed in the last three calendar years.” Change made’. We request clarification on why this change doesn’t appear in the current proposed standard and Implementation Plan.
Delete the reference to PRC-026-1 in 4.1.1 and 4.1.3 in the Applicability section. Leave the references simply as Attachment A. Delete ‘This’ in the 1st line of the 4th paragraph under 5. Background:. At the end of the 6th line and beginning of the 7th line in the same paragraph, delete ‘of security’. Hyphenate 30-, 60-, 90-calendar days and similar construction with calendar months throughout the standard. At the end of each of the first three bullets in 1.2 Evidence Retention the phrase ‘following the completion of each Requirement’ appears. Since each bullet only refers to one requirement what does this phrase mean when applied to Requirements R1, R2 and R3 individually? Why is the timing for notification in the VSLs for the Transmission Owner in Requirement R2 and the Generation Owner in Requirement R3 different from that for the Planning Coordinator in Requirement R1? Shouldn’t they be the same? We recommend that all changes made to the standard be reflected in the RSAW as well.
Individual

John Brockhan
CenterPoint Energy
Yes
No
CenterPoint Energy recommends additional clarification be provided for identifying and the reporting, or not reporting, of Elements that trip from power swings during system disturbances. We believe certain tripping should be excluded, such as, when reconnecting islands and during black start restoration. We suggest the following sentence be added to Requirement R1, Criterion 1: “Notification shall not be provided if an Element trips from a power swing that occurs during operator-initiated switching to reconnect islands, to restore load during Black Start activities, or to synchronize a generating unit to the system”. In addition, it may be needed to clarify that tripping of Elements from voltage or frequency oscillations due to power system stabilizer issues are not to be reported.
No
CenterPoint Energy recommends that requirements for Corrective Action Plans (CAP) be removed in the draft PRC-026-1 standard. The operation of a Protection System during a non-fault condition due to a stable power swing would be a reportable Misoperation under PRC-004. Both the current enforceable version of PRC-004 and the one under development require a CAP for a Misoperation. Consistent with one of the recommendations from the NERC Industry Experts initiative, CenterPoint Energy believes that there should not be duplicative requirements in NERC Reliability Standards.
Yes
CenterPoint Energy recommends removing references to “unstable” power swings in the draft PRC-026-1 standard, as we believe tripping from unstable power swings is random and not indicative of an Element being more susceptible to a stable power swing. Where tripping actually occurs for an unstable power swing is dependent on the location and nature of the event, system conditions, and where additional Element outages occur during a disturbance. We are not aware of any available technical information or analysis to justify that an Element is more susceptible to a stable power swing if it has tripped from an unstable power swing.
Group
Seattle City Light
Paul Haase
No
Seattle City Light is not convinced that this Standard is warranted, and does not find comfort in the tortured process associated with developing the recommendations of the PSRPS document. The changes, as far as they go, do add some clarity to R1.
Yes
Yes
Seattle appreciates the effort of the drafting team to separate auditable activities into an individual requirement or subrequirement rather than blending them together.
Yes
Seattle appreciates the effort of the drafting team to separate auditable activities into an individual requirement or subrequirement rather than blending them together.
No
Seattle appreciates the efforts of the drafting team to provide application guidance and technical basis information and welcomes the trend towards such implementation documentation throughout

the standards development process. For PRC-026, this material has improved somewhat compared to the original draft, but application of the standard remains insufficiently clear for Seattle to recommend an affirmative ballot at this time. More examples and/or a flow chart or something similar to fully delineate the steps in the process are wanted.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
Yes
Yes
Yes
Yes
The requirement to develop a CAP in R5 should be edited to allow the owner to make a declaration that corrective actions would not improve BES reliability if that is the case and therefore action will not be taken. This is consistent with PRC-004-3, R5.
No
The “Exclusion of Time Based Load-Responsive Protective Relays” on p 25 indicates that time delayed Zone 2 and Zone 3 relays are intended to be excluded from this standard. However, many of the figures reference Zone 2 relay compliance or non-compliance; in particular, see Figure 10. That seems to imply that the Zone 2 relays in the example do need to comply with this standard. If we are told that time-delayed relay elements are to be excluded, does this imply that the Zone 2 relay is being used in a directional comparison blocking (DCB) scheme? If so, should that not be clearly identified? (Only Figures 3 and 12 identify the element in question as being a pilot Zone 2, and pilot could refer to may schemes that would not be impacted by extending beyond the defined impedance boundary). Similar to that example would be the use of Zone 2 relay elements to assert permission in a permissive overreaching transfer trip (POTT) scheme. It is likely that Zone 2 relay elements in a POTT scheme could extend beyond the impedance characteristic defined in Attachment B, but the only regions that would result in tripping in less than 15 cycles are the overlapping Zone 2 regions that result in POTT scheme activation, which would most likely be fully contained in the region defined in Attachment B. Tri-State believes that a statement or example clarifying that such a protection system is compliant would be beneficial to applicable entities as well as the compliance monitoring entities.
Yes
No
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) We largely agree with the applicability changes. We thank the drafting team for removing Transmission Planner and avoiding the confusion that has occurred in so many other standards from joint responsibility to meet the same requirements as the PC. (2) We are concerned with the removal of the RC. Per the SDT’s response to our comments regarding which SOLs (planning horizon is covered FAC-010 and operating horizon is covered in FAC-011), the SDT indicated that they intended for both to apply. Since the SOL methodology that applies in the operating time horizon is written by the RC, the PC may not be familiar enough with the RC’s methodology to determine which

operating horizon SOLs are due to angular stability. Wouldn’t it be easier for the RC to notify the PC of those operating SOLs caused by angular stability?
No
(1) We agree that the clarity of Requirement R1 is improved but we still have a couple of concerns. (2) Why is the PC required to notify the GO and TO of Elements that were involved in actual events when the GO and TO are the entities that notify the PC in the first place? Doesn’t the PC just need to notify the GO and TO when those Elements are no longer susceptible to tripping from stable power swings? (3) In Criterion 4, why are unstable power swings included? Elements should trip due to unstable power swings. Why does the GO and TO need to modify relaying for unstable power swings? Since PRC-006 only requires the PC to simulate the UFLS Program every five years, it seems that requiring the PC to identify the same Elements that form a UFLS island boundary every year is unnecessary. Criterion 3 should be modified to clarify that this notification is only necessary once every five years when the UFLS study is completed.
Yes
(1) We agree with splitting the requirements because the GO simply is not privy to the same information as the TO to identify island boundaries. However, it is reasonable for the GO to work with the TO and TOP to determine the cause of the relay operations to be from a stable power swing. (2) We believe the time horizons for both requirements R2 and R3 need to be modified. Both are currently long-term planning which is one year or longer into the future. Since this is an evaluation of actual events, we believe the Operations Assessment time horizon is more accurate. (3) Why is tripping from unstable power swings included in these two requirements? Relays should trip due to unstable power swings. The FERC directive compelled NERC to develop a standard that requires protection systems to be able to differentiate between stable power swings and faults. The directive did not require NERC to specifically address unstable powers swings. We recommend removing unstable power swings from both R2 and R3.
Yes
We agree the requirement is much clearer.
No
We agree splitting the requirement into two requirements where one deals with assessing the Protection System and the other deals with developing a CAP is an improvement. However, we continue to believe the Requirement R6 is an administrative requirement that meets P81 criteria and should be removed. The only way the R6 will ever be violated is if an entity fails to update their paperwork on the CAP. How does failing to update documentation not administrative? How does ensuring the documentation is updated by enforcing penalties serve reliability? How is this consistent with RAI which is intended to refocus compliance and enforcement on those risks most important to reliability and not on documentation issues?
No
(1) The “Application Guidelines and Technical Basis” are quite helpful and definitely do provide additional insight into the meaning of the requirements. However, we believe additional modifications are necessary. (2) On page 18 in the second paragraph, we do not believe the paragraph captures all of the reasons for changing the applicability of the standard. We believe that changing the applicability makes that standard consistent with the other relay loadability standards and makes the standard consistent with the functional model. These reasons are important to capture as they are more substantial than those listed. (3) In the Requirement R1 paragraph on page 20, please change “and other NERC Reliability Standards” to PRC-006. There are two main standards (or five depending on which version of TPL are used) that drive identification of Elements susceptible to stable power swings. They are the UFLS standards and TPL standard(s). As written, this paragraph is too open ended and could lead to confusion. (4) We suggest that a diagram should be developed depicting the example in the second paragraph on page 24. (5) In the “lens characteristic” examples, we suggest that annotating the figure with the actual lens point would be helpful in understanding the “lens characteristic”.
No
We do believe the 36-month period of implementation for R4 is sufficient. However, we do not understand why R5 and R6 do not have the same effective date as R4. They are dependent on R4 with the “pursuant to Requirement R4” and “pursuant to Requirement R5” clauses in the requirements. To avoid the confusion associated with monitoring compliance to R5 and R6 when

they cannot technically be violated, please align the effective date for R5 and R6 to R4 to avoid this confusion.
Yes
(1) We believe the data retention section is inconsistent with the RAI. RAI is intended to refocus the ERO's compliance monitoring and enforcement efforts on those matters that pose the greatest risk to the reliability to the BES. This involves making compliance monitoring and enforcement forward looking to provide reasonable assurance of future compliance and reliability. How does a three-year data retention requirement support this forward looking vision of RAI? We suggest that the data retention should be no more than one year, based on the annual cycle established in this standard. (2) Why is 36 calendar months in bullet 4 instead of 3 calendar years that is used in the first three bullets? It seems they should be the same to avoid confusion. Notwithstanding our earlier comments regarding making the data retention period no longer than one year, we suggest using consistent language throughout the data retention section. Thus, use either 36 calendar months or three calendar years, but not both.
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
BPA requests a revision to R1 to separate customer notifications from technical analysis. R1.1 Each Planning Coordinator shall, at least once each calendar year, identify each Element in its area that meets one or more of the following criteria…. R1.2 Each Planning Coordinator shall provide notification to each respective Generator Owner or Transmission Owner that owns an Element identified in R1.1.
Yes
Yes
BPA agrees that Attachment B is an improvement; however, it could be better. It appears that the only way to verify compliance is through a graphical comparison of the relay characteristic and a lens characteristic that is described in the Application Guidelines. The Application Guidelines give one example of calculating six sample points on the lens characteristic. BPA was able to work our way through the example, but it was somewhat difficult and required lots of reading between the lines. BPA requests more explicit explanations of what is expected to show compliance and how to develop the lens characteristic.
Yes
No
BPA agrees that Attachment B is an improvement; however, it could be better. It appears that the only way to verify compliance is through a graphical comparison of the relay characteristic and a lens characteristic that is described in the Application Guidelines. The Application Guidelines give one example of calculating six sample points on the lens characteristic. BPA was able to work our way through the example, but it was somewhat difficult and required lots of reading between the lines. BPA requests more explicit explanations of what is expected to show compliance and how to develop the lens characteristic.
BPA cannot estimate if the implementation plan provides sufficient time until BPA determines how many elements that R1 applies to.
Yes
BPA suggests re-ordering the requirements for continuity because the standard is working/designing the system to prevent trips by load-responsive relays unnecessarily. R1 (PC identify criteria influenced Elements ANNUALLY) R4 (GO/TO evaluate elements identified by the PC's identifier of Gen restraint, line part of SOL angular, UFLS line boundary) R5 (GO/TO develop a CAP for at risk protection on R4 elements) R6 (GO/TO implement the CAP) R2 (TO notify PC within 30 days if an element trips by load-responsive protection due to swings or forms a boundary during a actual

system Disturbance) R3 (GO notifies PC within 30 days if element trips by load-responsive protection during a swing)
Individual
Kurt LaFrance
Consumers Energy Company
No
The Transmission Owner and Generator Owner on their own do not have the capability to determine if a trip was caused due to a swing. In most cases the Generator Owner has no knowledge of events on the transmission system, and in many cases the Transmission Owner may only own one terminal of a transmission line. Given the available data for a single terminal, there is no reliable way for an Owner to determine if a trip was due to a fault or a swing. The Transmission Planner and/or Reliability Coordinator have the broad system perspective to track how a swing moves through the transmission system and impacts each element and should determine whether any given event was involved a swing through a specific Element.
Yes
No
R2 and R3 require modification to provide clarity in how the Owner will determine if any given trip is due to a swing. Without specific guidance on how to identify and document when a swing occurs and whether that swing caused a trip, we do not believe we are able to comply with R2 or R3. For instance, if an Owner only has electromechanical relays on a terminal, and does not own the other terminal(s) of that element, how is it to determine the impedance trajectory and whether or not that trajectory was a swing or a fault?
Yes
Yes
No
The revised application guidelines are very helpful, but need to be expanded to include guidance on how to comply with R2 and R3, specifically how Generator Owners and Transmission Owners are expected to determine whether a trip was due to a swing. Given the lack of guidance we have at this point, we feel we are unable to comply with R2 or R3.
Yes
No
Individual
Richard Vine
California ISO
No
The California ISO does not agree with the change to remove the Transmission Planner in the Applicability section and in Requirement R1. The California ISO supports continuing to include the Transmission Planner in Requirement R1 as suggested by the PSRPS Report.
No
The California ISO does not agree with the change to remove the Transmission Planner in the Applicability section and in Requirement R1. The California ISO supports continuing to include the Transmission Planner in Requirement R1 as suggested by the PSRPS Report.

Additional Comments

Oncor
Gul Khan

2. Do you agree that the revisions to Requirement R1 improved clarity while remaining consistent with the focused approach of using the Criteria which came from recommendations in the PSRPS technical document[1] (pg. 21 of 61)? If not, please explain why and provide an alternative, if any.

   ☒ Yes

   ☐ No

   Comments:

3. The previous Requirement R2 was split into Requirement R2 for the Transmission Owner and Requirement R3 for the Generator Owner in order to clarify the performance for identifying Elements that trip. Did this revision improve the understanding of what is required? If not, please explain why the Requirement(s) need additional clarification.

   ☒ Yes

   ☐ No

   Comments:

Arizona Public Service
Donna Turner

2. Do you agree that the revisions to Requirement R1 improved clarity while remaining consistent with the focused approach of using the Criteria which came from recommendations in the PSRPS technical document[2] (pg. 21 of 61)? If not, please explain why and provide an alternative, if any.

   ☒ Yes

   ☐ No

   Comments:

3. The previous Requirement R2 was split into Requirement R2 for the Transmission Owner and Requirement R3 for the Generator Owner in order to clarify the performance for identifying Elements that trip. Did this revision improve the understanding of what is required? If not, please explain why the Requirement(s) need additional clarification.

   ☒ Yes

   ☐ No

   Comments: