Meeting Notes

Project 2010-13.3 – Relay Loadability: Stable Power Swings Standard Drafting Team

March 31-April 3, 2014
NERC
Atlanta, GA

In-person Meeting

Administrative

1. Introductions and chair remarks

The meeting was brought to order by Mr. Middaugh, chair, at 1:03 p.m. Eastern Monday, March 31, 2014. He thanked everyone for joining and to finally meet in-person to discuss the proposed standard. Mr. Barfield took roll of members and observers. Those in attendance were:

Name	Company	Member / Observer	In-person (IP) / Web (W)			
			3/31	4/1	4/2	4/3
Bill Middaugh, P.E.	Tri-State Generation & Transmission Association, Inc.	Chair	IP	IP	IP	IP
Kevin W. Jones, P.E.	Xcel Energy, Inc.	Vice Chair	IP	IP	IP	IP
David Barber, P.E.	FirstEnergy	Member	IP	IP	IP	IP
Steven Black	Southern Company	Member	-	-	-	-
Ding Lin	Manitoba Hydro	Member	-	-	-	-
Slobodan Pajic	General Electric Energy Consulting	Member	W	W	-	-
Fabio Rodriquez	Progress Energy – Florida	Member	IP	IP	IP	IP
John Schmall	Electric Reliability Council of Texas (ERCOT)	Member	IP	IP	IP	IP
Matthew H. Tackett, P.E.	Midcontinent Independent System Operator (MISO)	Member	IP	IP	IP	IP
Ken Hubona	Federal Energy Regulatory Commission (FERC)	Observer	IP	IP	IP	IP

Name	Company	Member / Observer	In-person (IP) / Web (W)			
			3/31	4/1	4/2	4/3
Scott Barfield-McGinnis, P.E. (Standard Developer)	North American Electric Reliability Corporation (NERC)	Observer	IP	IP	IP	IP
Michael Gildea (Regulatory)	North American Electric Reliability Corporation (NERC)	Observer	-	IP	-	-
Phil Tatro, P.E. (Technical Advisor)	North American Electric Reliability Corporation (NERC)	Observer	IP	IP	IP	
Benjamin Fields	Georgia Transmission Corporation	Observer	W	W	W	
Gene Henneberg	NV Energy	Observer	W	W	W	W
Hari Singh	Xcel Energy	Observer	W	-	-	-
Phil Winston	Georgia Power	Observer	-	IP	-	-
David Youngblood	Consultant (Luminant Energy)	Observer	IP	IP	IP	IP

2. Determination of quorum

The rule for NERC Standard Drafting Team (SDT or team) states that a quorum requires two-thirds of the voting members of the SDT. Quorum was achieved as seven of the nine members were present at the beginning of the meeting.

3. NERC Antitrust Compliance Guidelines and Public Announcements

NERC Antitrust Compliance Guidelines and public disclaimer were reviewed by Mr. Barfield. There were no questions. Mr. Barfield also referred everyone to the two new NERC policies and demonstrated where to find them on the NERC website. The policies are related to use of the email listserv and standard drafting team meeting conduct. Attendees were reminded of the antitrust guidelines, disclaimer, and policies at the start of each subsequent day.

4. Review team roster

Mr. Barfield displayed the roster that is posted on the NERC project page and noted it has not been changed since being initially approved by the Standards Committee.

5. Review meeting agenda and objectives

Mr. Barfield reviewed the meeting agenda and objectives noting that the team finished Requirement comments at the last meeting. The meeting first day will focus on the remaining comments in the Rationales.

Mr. Barfield also noted that this standard would be balloted under the new Standards Balloting System (SBS) that goes live on April 1, 2014. There will be an industry webinar on April 8, 2014 from 1:00 p.m.-3:00 p.m. Eastern.

Agenda

1. Continue with Standard Development

The team continued from the last meeting with Mr. Henneberg's comments received via email concerning Requirement R4. Mr. Henneberg attending the meeting remotely expressed concern that referencing TPL-001-4 may go beyond the contingencies that do not have to be addressed in the planning standard. Mr. Tatro reiterated the SPCS approach to use existing planning studies and information. Also, that there is a balance between Protection System security and dependability (i.e., not trip for stable power swing, but trip for an unstable power swing). Mr. Henneberg believed the Planning Coordinator (PC) and Transmission Planner (TP) will be required to obtain more data from the planning studies. For example, impedance and trajectory profiles. This ended the previous discussion concerning the Requirements.

Moving into Rationale #1, Mr. Middaugh asked what the team thought about the use of Protection System margin. Mr. Barber noted that PJM has a document that discusses how to apply margins for zones 1, 2, and 3. Supposedly, in a way the approach is like an extension to PRC-023-2 because if the loading went beyond the PRC-023-2 standard it would accommodate a power swing. Mr. Schmall believed it would be easier to adjust the impedance characteristic rather than running additional simulation. Mr. Tatro concurred and that it would leave the planner other options (e.g., out of step blocking) or the proposed Requirement bullet to have a consultation with the Protection System owner for other conditions (e.g., over constrained line). Mr. Tackett expressed concern to minimize resource burden and likes the margin approach. Mr. Tatro noted that striking a balance between a margin and the angle would be a way to evaluate the power swing.

In Rationale #2 (Requirement R2), Mr. Schmall noted the team should not assume that the extra assessments required in TPL-001-4 are already being performed in that stakeholders may not fully understand how the proposed PRC-026-1 standard will be implemented. Also, that it is not readily apparent that a planner would be revealing power swings in general. Mr. Henneberg noted that identifying power swings has been a challenge for NV Energy because their system weaker than the surrounding stronger systems causing power swings to pass through the NV Energy system. He is also concerned that planning staff may not be able to determine the impedance trajectory because the model is insufficient nor have the documentation available. If so, places that currently have power swing blocking, NV Energy would probably leave it in place. His past experience is that these models do not provide adequate information to make the necessary judgments regarding power swings. Mr. Tatro noted that depending on loading and transfers will affect the outcome of analyses.

Mr. Henneberg questioned what would be the impact of applying power swing blocking (PSB) functions on an Element terminal, even though that terminal turned out to not be particularly vulnerable to experiencing swings. Mr. Tatro noted that he would expect that the Element would no longer be subject to the standard.

In Rationale #2, Mr. Schmall believed the expectation that the PC/TP would be performing the impedance characteristics each calendar year logically follows Requirement R1. The current draft for Requirement R2 does not include a timing requirement and there does not appear to be critical to reliability.

Mr. Schmall noted in Rationale #3 (Requirement R3) that he expects that the task of communicating to the Generator Owner (GO) and Transmission Owner (TO) to be performed each calendar year logically follows from Requirements R1 and R2. The current draft for R3 does not include a timing requirement and there does not appear to be a critical reliability need for adding one. There were no questions.

Mr. Jones questioned if the three-month time period in Requirement R4. Mr. Barber agreed that the time period is too short to allow for trip checks and other work. Mr. Middaugh asked if it is acceptable to have different implementation plan periods for applying setting changes versus replacing or modifying equipment. Mr. Barfield was concerned that the Corrective Action Plan (CAP) intent is to remedy a specific problem with a timetable and that the open ended timetable would be a concern to the Commission. Because of this he asked Mr. Hubona if in his opinion if the CAP approach over a defined period would be an acceptable approach. Mr. Hubona believed the approach would be acceptable. Mr. Jones expressed a concern that during auditing that the Regional Entity may raise questions about the speed to which the CAP is being implemented. With adding “develop a CAP” in the proposed Requirement R4, bullet 2 would allow the team to keep the three-month period; however, the team discussed and agreed to change the time to six months. Additional questions were raised about how to accomplish the fourth bullet because the Generator Owner and Transmission Owner are having to consult with the Planning Coordinator and Transmission Planner which no performance criteria in Requirement R4, therefore, no potential violation of the standard.

Mr. Barfield questioned if it was sufficient for a planner to evaluate Elements every third year rather than annually. The team discussed whether or not it is necessary for the PC/TP to perform this work annually and decided that annually made the most sense based on Mr. Tackett’s points about the changing market place (e.g., wind generation, fuel pricing, etc.)

Mr. Barber questioned if the planner found different operating situations with multiple power swing characteristics, how would either the PC/TP, as well as, the GO/TO draw a conclusion to what settings to use. For example, which is the optimum characteristic? Mr. Rodriquez pointed out that there are an unlimited number of scenarios to find worst case and it would be left to the planner’s judgment. The characteristic must be for the specific event studied. Mr. Barfield agreed and questioned if there could be a case where the characteristic may for one event would not be optimum for another contingency. The team agreed that the worst case would need to be determined. Mr. Tackett noted that the planner may decide it may be better that certain characteristics/settings not apply in order not to sacrifice dependability for tripping on an unstable power swing.

Mr. Youngblood asked, as in Requirement R4, the entity would need to be able to demonstrate compliance with each impedance characteristic supplied by the planner. If so, there may be characteristics that fall within more than one bullet under Requirement R4.

Because of this, the team changed Requirement R2 to more closely connect the impedance characteristics to the specific Element under study. Comporting changes were made to Requirement R4 for consistency.

Mr. Middaugh questioned if it is sufficient to explain the component of an apparent impedance characteristic. Mr. Barfield noted that if it is widely understood, it should not be a problem; however, if it is important to ensure the correct information is communicated, the team may need to consider having a requirement add specificity to what is required to accomplish certain requirements. Mr. Tackett noted that all of the different information may not be needed for every case. Regarding Rationale #3 (Requirement R3), Mr. Schmall noted that PSS/E and PSLF will provide an R-X impedance plot with time. There were questions about what range of points should be provided by the planner and how to explain it.

The team revisited the proposed Requirement R4 concerning how to work through the performance of the bulleted items and within the time period. Several approaches were considered. Both Mr. Jones and Mr. Youngblood agree there should not be a case where a GO should trip for a stable power swing. The team agreed that Requirement R4, bullet four would not occur very often and may have little value including it. The current wording is: "Demonstrate that operation of the Protection System for a stable power swing is acceptable in consultation with the Planning Coordinator and Transmission Planner." Mr. Barfield was concerned about the PC/TP not having a performance requirement and his experience has been that entities generally avoid "agreeing" to certain aspects of Protection System settings. The team concluded that developing language similar to standard PRC-023-2, Requirement R3 would be close to what the team is looking for, conceptually. Mr. Barfield agreed to develop sample text for review.

Mr. Barfield provided a draft rewrite of Requirement R4 to try and separate criteria between making Protection System changes and the case where the GO/TO needs to have a consultation with the PC, TP, and RC. The team reviewed and made modifications. Mr. Jones noted that an entity should only be using the consultation criteria in Requirement R4 as a last resort. Mr. Tackett was further concerned that without specific criteria it would not be measurable. The team agreed that for the consultation criteria, if used by an entity, there would need to be a specific set of conditions to discourage excessive use. The team concurred on adding a caveat where the GO/TO is unable to achieve dependable fault detection or required out-of-step tripping, it must obtain the agreement of the Planning Coordinator, Transmission Planner, and Reliability Coordinator that Protection System operation for the provided apparent impedance characteristic is acceptable.

Mr. Jones suggested a re-read of all four proposed Requirements for consistency and flow before moving on to other items. The considered rewording of Requirement R1, Criterion #4 ("islanding") and decided to wait for Mr. Tatro to rejoin the group before moving forward. Mr. Youngblood noted that Requirement R1, Criterion #5 (e.g., TPL-001-4) that without better communication of settings that the criterion would be unhelpful to the entity. Mr. Middaugh believed that the new TPL-001-4 will drive better communication among planning and protection engineers. Mr. Rodriquez noted that most models do not have extensive protective modeling and where identified, the planner may have to consult with the protection engineer to obtain more information to determine any negative impacts.

The team reviewed Requirement R2. Mr. Barber noted that an entity might have actual data to which it could use in its determinations. Mr. Schmall believed that in the end that simulation should be used to evaluate the power swing conditions. Mr. Middaugh noted that the actual event may have determined that the power swing was unstable during an N-4 event, but when studied it was found that during an N-2 simulation there was a stable power swing which needed to be addressed. The team evaluated changing the lowercase "disturbances" to the capitalized Glossary of Terms Used in NERC Reliability Standard definition of "Disturbance." The team reviewed the definition and concurred using the NERC glossary defined term as it most closely matches #2 in the definition for "any perturbation to the electric system."

The team made minor changes to Requirement R3 for clarity. No substantive changes were made to their initial draft of the requirement. Last, the team re-evaluated Requirement R4 for completeness after working on it early in context with the first three requirements. Mr. Barfield asked if Requirement R4, #3 completes the expected performance. For example, if an entity had a consolation and obtained agreement, but some other work needed to happen the entity is compliant and is not required to do anything else because it satisfied #3. Mr. Tackett noted that #3 is agreement to allow tripping; therefore, no other work is required. If no agreement is achieved, the entity would need to comply with #1 or #2. Mr. Tackett also questioned the use of "tripping" because this terminology is not used in PRC-023-2. It was unknown why "tripping" is not a term this is used.

Prior to starting on the Attachment 1 document that is referenced in Requirement R1, the team reviewed the Rationales for consistency with the Requirement changes made. For example, the team replaced "operate" with "trip." Rationale #1 received minor revisions. Rationale #2 was revised to be consistent with the language changes made in Requirement R2. Rationale #3 was revised to be consistent with the language changes made in Requirement R3. Rationale #4 was revised to be consistent with the language changes made in Requirement R4 and included changing the "four criteria" to "three options."

The discussed components of Attachment 1 that requires development for the corresponding Requirement R2. Discussion was initially around Requirement R1 which describes five criteria for identifying Elements subject to the standard. The team was concerned about how the planner will approach evaluation of power swings on the applicable elements. Mr. Jones noted he would like to see a one-size fits all approach to the five criteria. Mr. Barber also noted that it would not be advisable to try and run additional simulations to stress the locations identified in Requirement R1. If so, the planner would have to increase the number of base cases that it would need to have.

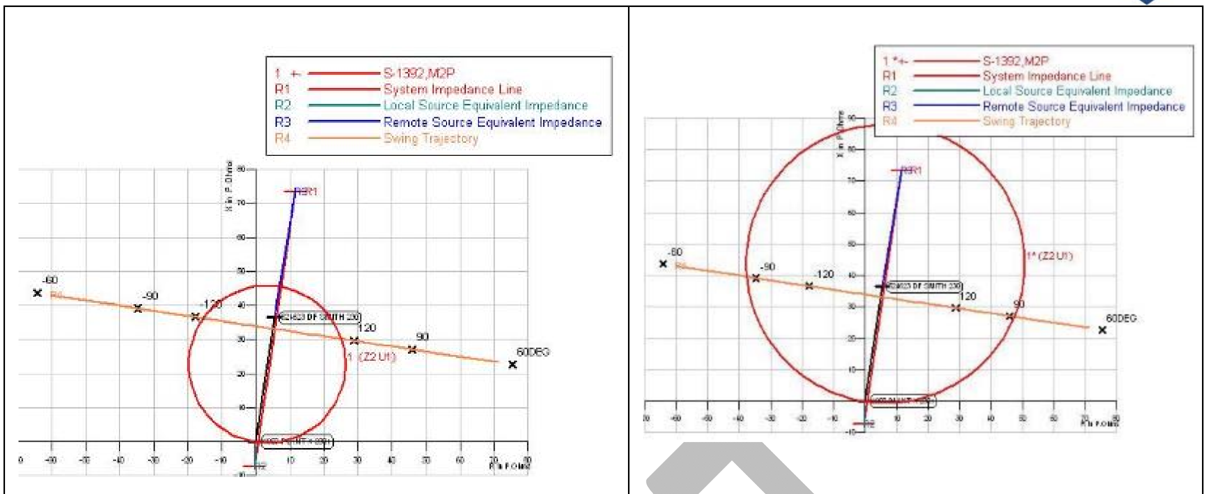
Mr. Tackett suggested the planner use a margin in the simulations. For example, the planner would run its simulation without relays to determine the power swings are stable and there in no instability. From there, the planner would apply relays to the simulation with a margin on the Elements prescribed in Requirement R1. Additionally, the team needs to remember that planners have multiple cases to manage. For example, annual assessments, five-year assessments, peak conditions, and seasonal variations.

Mr. Tackett proposed options for the proposed Attachment 1 for stressing the system beyond the normal planning contingencies (i.e., the approved TPL-001-4) for analysis to check and see if some level of margin exists. Similar to how PRC-023-2 is structured, the attachment could list several options and the applicable entity would need to demonstrate that the relays should not trip for stable power swings under one of the options. He noted that criteria could include such things as increased clearing time margins, initial condition adjustments to increase element loading (re-dispatch or incremental transfers), and testing a three-phase fault with delayed clearing (which is an extreme event). If any of these criteria during simulation resulted in a stable power swing and the relay did not trip for such a swing, the entity could conclude that there is some level of margin above the normal planning criteria; therefore, exclude it from the applicable Elements. If any of the criteria resulted in an unstable power swing (with no tripping simulated), the entity could conclude that the stable power swing analyzed via the normal planning contingencies are close to the most severe stable power swings.

Mr. Rodriquez provided information about the use of margins in planning. He noted that planners currently use the highest margin, for example, using the maximum possible output of all generating units. The point is to be mindful of how margins are employed.

Mr. Jones provided two mho impedance circles for discussion below regarding margins. At Xcel, they have designated places where interconnection separation is planned and they additionally separate into three smaller internal islands. He noted that lines that are designated to separate use out-of-step tripping and out-of-step blocking is used on all other lines.

For example, the planner could use a mho circle expanded beyond the normal actual setting to provide a margin to test the relay element to see if it is susceptible to picking up on a stable power swing. They would model the expanded mho by a set multiplication factor in their stability software and would run studies based upon TPL requirements to see if the expanded mho is encroached upon. If it is, the planner will supply the R-X impedance data versus time to the TO/GO that owns the protection system under study. The TO/GO then uses the data to test the actual settings to see if it would trip for the stable swings in Requirement R4.



Mr. Jones agreed with the approach to use impedance characteristics and not run additional studies. In doing so, it requires the protection engineers to provide additional information to the planners and with instructions on how to apply a margin.

Mr. Middaugh questioned why the planner would need the expanded margin for simulation. Mr. Schmall explained that the expanded margin is needed to test for the stressed situation to be able to exclude the Element from being challenged by a power swing. Mr. Jones suggested using a 200% margin on zone 2 during simulations and if the Element trips during simulation, it would require the planner to provide the impedance characteristic to the GO and TO for evaluation under Requirement R4.

Mr. Schmall indicated that the team may have to decide whether to use an approach to use margins or prescribing the contingencies to study. As a planner, he noted that it would easier to employ margins than to run additional models. Since the soon to be enforceable TPL-001-4 implicitly requires the use of generic or actual relay models, the margin approach seems practical.

Mr. Jones suggested an approach of using 125% over 150% margin using a generic mho circle reach set to comply with 125% loading instead of 150% (PRC-023-2) loading so that a bigger mho circle could be evaluated, which will identify more problems with power swings. Mr. Tackett noted that the margin may capture more Elements listed in Requirement R1 that are challenged by power swings. Discussion led to the planner running simulations which would remove Elements from the list. Mr. Barfield was concerned because the proposed standard's requirements do not allow that action. He noted that Requirement R1 flags the Element, R2 requires the planner to provide whatever apparent impedance characteristics for those Elements. Requirement R3 requires the planner to provide the apparent impedance characteristics to the GO/TO. In Requirement R4, the GO/TO would evaluate whether their Protection System for the subject Element would meet the characteristic or if it would need to change settings, or modify or replace Protection System components to mitigate the power swing. The earlier question which led to proposing Attachment 1 was which characteristic to send to the GO/TO. Mr. Tackett explained that for a simulation that was run that resulted in instability would not be included; however, the planner would need to strike a balance in what characteristic to provide to the GO/TO for the stable power swing case. Several team members agreed.

Mr. Tatro asked the team to recap the discussion to better understand what the discussion needed to answer. Mr. Barber responded that the team was attempting to determine the best approach for the planner to determine what apparent impedance characteristics to provide to the GO/TO. He also noted one approach was to provide those characteristics within a percentage (margin) of the operating characteristics. Mr. Tackett added that another approach being considered was to add a margin in the simulation to accomplish the same thing. Mr. Tatro expressed his understanding to be that the planner would provide the worst case characteristic to the GO/TO and the GO/TO would perform the proposed Requirement R4.

Mr. Tatro noted based on the discussion that Requirement R1, #5 could be perceived in two ways; (1) as including everything else beyond #1 through #4, or (2) if the planner knows anything else, then include it. Given those two ways, he suggested that PRC-023-2, Attachment B, Criterion B5 may be a better approach. Mr. Henneberg agreed and encouraged taking an approach that does not burden the planner over what is already expected. Mr. Middaugh asked the team if using the stability angle as measure would be acceptable. Mr. Tatro noted that an R-X impedance plot would be dependent on the source impedance and receiving end impedance. Mr. Schmall asked if there was a way to describe for the five Requirement R1, Criterion 1-5 in Requirement R2 that each Element is based on the specific contingency that created the situation. The team liked the approach.

The team reviewed Requirement R1, Criterion #4, "Elements that form a boundary of a potential island of the BES as identified by the Planning Coordinator or Transmission Planner that may form an island" and considered alternative text. Mr. Tatro noted that he believed that Criterion #4 best represented the three different islanding criteria as found in PRC-006-1, Requirement R2, and Parts 2.1 through 2.3. The revised Criterion #4 changed to, "Elements that have formed the boundary of an island during an actual system disturbance or within an angular stability planning simulation."

Based on discussion about Attachment 1, the team decided to eliminate the attachment and consider an approach of using a table in Requirement R2 to illustrate the criteria the planner will use in simulating the conditions for Elements in Requirement R1. The team agreed that the planner only needs to simulate the condition which created the operating limit (i.e., Criteria 1 and 2), Special Protection System (SPS), or System Operating Limit (SOL). The criteria requires the condition to be enforced during the simulation. For criterion #3, Mr. Schmall questioned how prescriptive the standard needs to be on how you step through the simulation when evaluating the power swing.

The method to which a planner would determine the apparent impedance characteristics for Requirement R2 presented significant problems with reaching clarity how to structure the requirement. Mr. Tatro noted that based on the issues the team may want to reconsider the current approach. Mr. Middaugh suggested taking the mho element and compare it to the Element in Requirement R1 based on the sending and receiving Thévenin equivalent that are 120 degrees apart in voltage and equal in magnitude. Mr. Jones agreed that could be a starting point and that the GO/TO would compare the Element's apparent impedance characteristic to determine if the Protection System is challenged. He agreed to draft some language that may be beneficial with getting the protection engineer involved earlier in the process with determining relays that are challenged on the Elements in Requirement R1.

The team developed the table concept further and established actions to be used by the PC/TP for each of the five criteria in Requirement R1. The actions provide clear expectations to the performance by the PC/TP to determine the apparent impedance characteristics for the Element in Requirement R1.

Mr. Jones provided three mho impedance characteristic figures for discussion as a sample screening process that would be used by the GO/TO against the Elements identified in the proposed Requirement R1. He noted that the points R1 and R2 represent the sources and in his example, would increase in magnitude if the source were weakened. The orange line bisecting the total system impedance illustrates the sources are equal in voltage magnitude. In the case of differing voltages, the orange line would become an arc toward the lower of the voltages and would provide a way to further analyze the susceptibility of the power swing trajectory entering the mho characteristic. Source impedances are calculated with system intact using sub-transient source impedances. The source voltages have an angular displacement of 120 degrees which is an industry accepted point to which instability occurs.

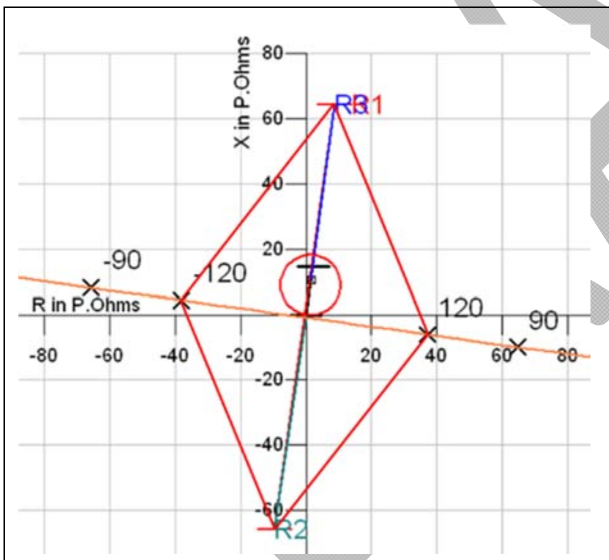


Figure 1. The zone 2 reach does not break out of the 120 degree power swing trajectory.

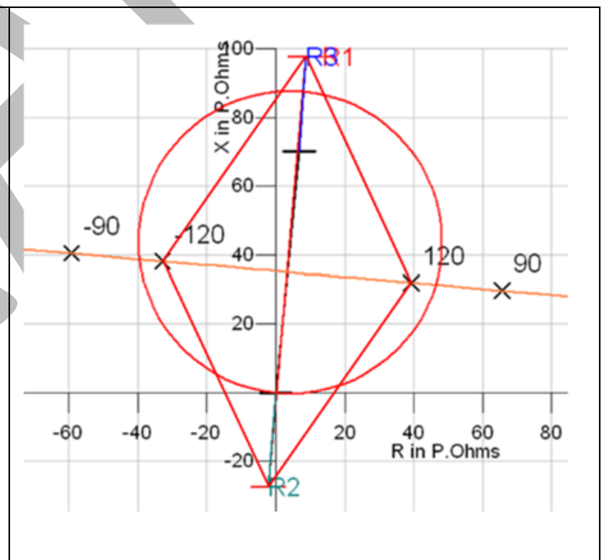
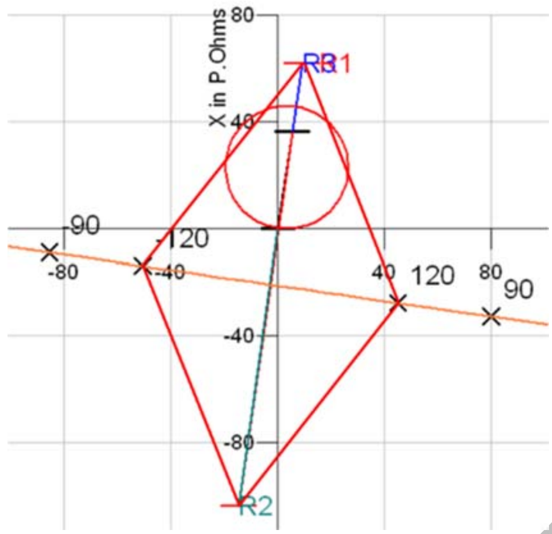


Figure 2. The zone 2 mho circle reach breaks significantly out of the 120 degree power swing trajectory.

	Intentionally Blank
Figure 3. The zone 2 mho circle reach breaks slightly out of the 120 degree power swing trajectory.	Intentionally Blank

Mr. Middaugh asked the team to provide additional thoughts on whether the concept has merit for further consideration. Mr. Schmall believe the concept would add complexity to the process. Mr. Jones theorizes that it would reduce the burden of the planner by reducing the number of identified Elements requiring simulation. A question was posed about how many potential Elements would be in scope. Mr. Tatro did not recall the SPCS determining the number of Elements. With respect to the proposed screening process, Mr. Jones theorized that an experienced protection engineer could evaluate 20 or more lines in a day using analysis software.

In reference to Figure 3, Mr. Barber asked if the protection engineer could adjust zone 2 such that it was inside the 120 degree voltage trajectory (i.e., the parallelogram). The team agreed that if the protection engineer could make an adjustment via the screening process, it would be a way to remove it from the list that would need to go to the planner for further evaluation and simulation. Mr. Henneberg agreed with the technical aspects in using the approach as provided by Mr. Jones. In response to Mr. Middaugh's previous question whether or not to pursue this approach, the team agreed to move forward with developing a requirement. The team created a new Requirement to have the GO/TO evaluate its protective relays that will reduce the number of protective relays from the list of Elements that would need to be simulated by the PC/TP, thus reducing the burden.

Mr. Tackett questioned if the team could consider looking at an 80/20 percent risk of a protective relay tripping on a stable power swing. For example, develop a method to identify those relays that will not trip for 80 percent of the stable power swings that challenge the relay recognizing that a percentage of the protective relays might experience a stable power swing beyond the screening process. He asked if the team should consider moving the proposed screening threshold hold from 120 degrees to 90 degrees. Mr. Tatro was concerned that the team or available resources would not be able to provide a technical basis for using a value different from the industry accepted value of 120 degrees for a point of instability. The team agreed that the proposed requirement should remain generic and provide additional detail in the Application Guidelines. The reason is that not all entities would go through the evaluation by protection engineers, as noted earlier, and that an entity may use planning staff and simulation software as an alternative. The team agreed that leaving the requirement less prescriptive allows flexibility for the entity to determine how it wishes to evaluate the protective relays. Mr. Jones noted he would like to give the 90-120 degree option additional thought for cases where the GO/TO have applied out-of-step blocking.

Mr. Youngblood questioned the auditability of the word “evaluate” and that the Requirement seemed open-ended. Mr. Jones suggested having an approach similar to PRC-023-2, Attachment A. The team agreed to add additional criteria to the proposed screening Requirement to increase the measurability of performance. The team established that the entity will need to verify its load-responsive phase protective relay are not expected to trip for a stable power swing using minimum criteria. The first of possibly two criteria included – 1. A distance relay impedance characteristic, used for tripping, that falls outside the parallelogram impedance boundary formed by connecting the sending and receiving source impedances to the system separation angle on the power swing trajectory using the following: The system separation angle shall be at least 120 degrees; All generation in service and all transmission Elements in their normal state; Sub-transient reactance for all machines; Equal magnitude sending and receiving Thévenin equivalent voltages.

There were several discussions about how to add additional flexibility to the criteria for screening. Mr. Barfield suggested an alternative approach to start off with the GO/TO consulting with the PC/RC/TP to identify the Elements for consideration rather than the PC/TP just developing a list. From there, the GO/TO would determine which protective relays are challenged by or susceptible to tripping during a stable power swing. Mr. Tatro noted that any requirements that improve the communication between planning and protection entities improves reliability, especially where entities are not vertically integrated. The team agreed to use the proposed approach to eliminate requirements which involve an exchange of information. Discussion moved to which entity the GO/TO should provide a list of the susceptible relays to for evaluation. The team believed the TP was the best entity. Mr. Middaugh argued that the GO/TO should provide the list to the PC/RC also, especially if they provided input to a potential concern to reliability. The team agreed not to include the PC/RC in the exception list, but to include them in Requirement where the GO/TO will have a consultation with those entities to determine what changes may be needed or are necessary.

The team further refined the approach in that once the GO/TO identifies a load-responsive phase protective relay that is susceptible to tripping during a stable power swing, it would provide that Element on a list to the PC/TP for simulation. The team discussed how the PC/TP would approach determining the impedance characteristics for a stable power swing. Mr. Schmall suggested having the TP simulate the condition based on its planning judgment. The team jumped ahead to the third criteria (i.e., Elements that have tripped due to power swings during system disturbances.) and Mr. Tackett suggested reducing the contingencies from N-17 to N-16, and so on until the swing becomes stable, for example. Mr. Rodriquez disagreed that performing simulations and changing the contingencies in such a manner to find the stable power swing characteristic is burdensome for the planner. The team agreed that the simulations that were not typical (e.g., an extreme disturbance), the planner would be allowed to modify the event (planning judgment) until it achieved a stable power swing solution. That way the planner would not be burdened with prescriptive requirement criteria that would burden the process of determining the stable power swing impedance characteristic.

Mr. Barfield raised a concern that the standard in Requirement R1 by its construction appears to require the GO/TO to touch each Element/relay annually and proposed that the team include something like “not previously mitigated.” Mr. Jones believed that annually would be acceptable and at first glance that even a three year periodicity may be sufficient. In contrast, the team considered the implication of only reviewing incremental changes to the list. Mr. Schmall noted that transmission topologies could have changed, thus the GO/TO would need to rescreen each relays on each of the Elements. Mr. Barfield agreed and noting that it was stated earlier that the screening process would be a minimal burden on the GO/TO. Mr. Jones agreed as well. Based on the burden and the need for catching any changes in the system, the team concluded that the GO/TO needs to consult the PC/RC/TP regarding the specified Elements every year as proposed in Requirement R1.

Mr. Jones provide the four figures below for discussion about the use of out-step-blocking for screening the list of applicable Elements. The figures were developed on the same basis as the 120 degree figures above. Source impedances are calculated with system intact using sub-transient source impedances. The source voltages have an angular displacement of 90 degrees which is an industry accepted point which maximum power transfer occurs. The figures were based on zone 2 relays where power swing blocking (PSB) is applied.

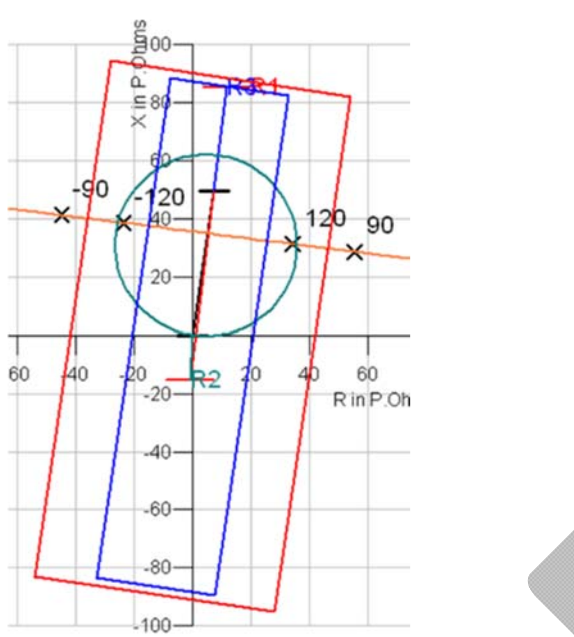


Figure 1. The zone 2 reach breaks out of the 120 degree unstable region, but is within the 90 degree maximum power transfer region.

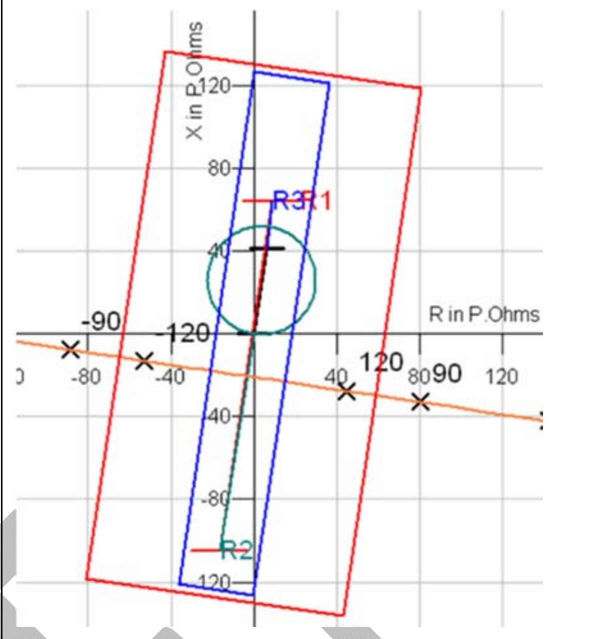


Figure 2. The zone 2 reach breaks out of the 120 degree unstable region, but is within the 90 degree maximum power transfer region.

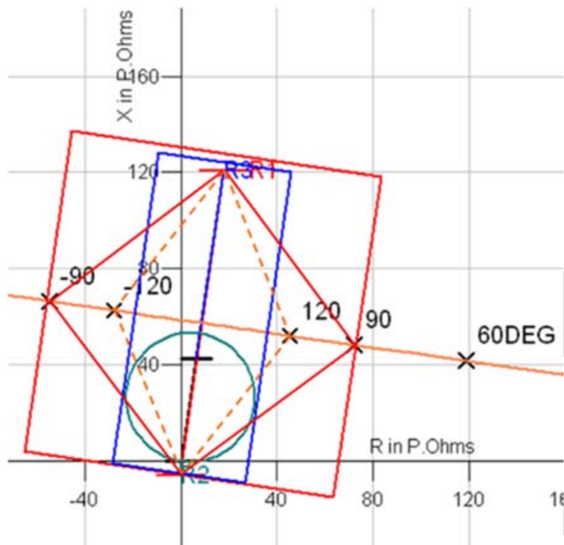


Figure 3. The zone 2 reach breaks out of the 120 degree unstable region, and breaks out of the 90 maximum power transfer.

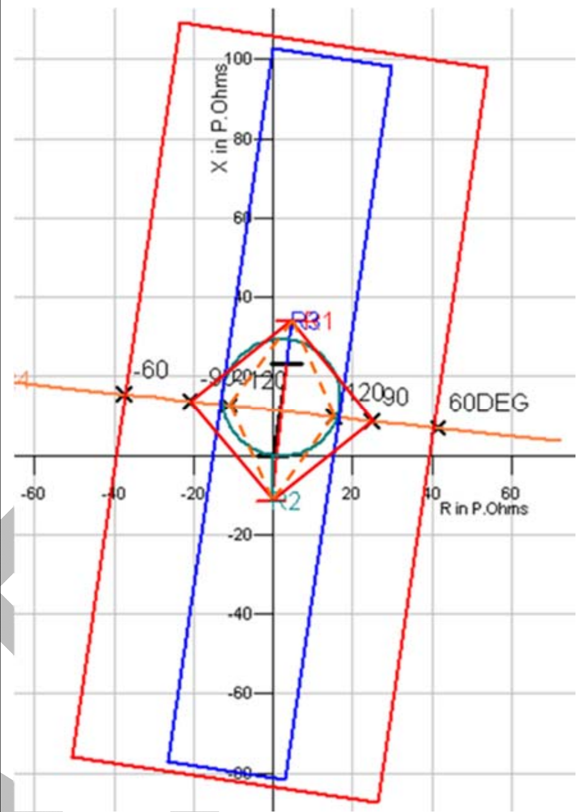


Figure 4. The zone 2 reach breaks out of the 120 degree unstable region, and ***barely*** breaks out of the 90 maximum power transfer region.

The team supported the screening approach for the second criteria for screening. Mr. Jones noted he would develop supporting information for the screening process and possibly a tool for industry to use. An additional bullet was added to the screening Requirement. Mr. Tackett provided revised text for the criterion for the screening Requirement. The team agreed that the revised text provided better clarity and additional detail.

The team reviewed the Requirement where the GO/TO provides the planner the list of Elements. Discussion revealed that the Disturbance associated with the Element needs to be provided as well; therefore, the additional performance was added to the Requirement. Additional discussion questioned how the entity would handle changes during the performance of the standard. For example, an Element coming off of the list or new information is revealed during the execution of the standard each year. Mr. Tackett noted that it is not reasonable to inject changes once the process is started because the planner would be continually adjusting its simulation models. The simplest thing would be to pick it up on the next cycle. The team agreed, but was still concerned about how to address Elements that are no longer on the list. Some believed the Element would remain on the list until the Element was no longer associated with the BES.

Additionally, the team added a time period to the Requirement where the planner provides the apparent impedance characteristic to the GO/TO. In consideration of the collective life cycle of the Requirements, the team reduced the time period for the GO/TO in verifying its settings or creating a Corrective Action Plan (CAP) from six calendar months to 90 calendar days. Mr. Barfield noted that the CAP probably needs an "implementation" Requirement for the CAP to be measurable. Otherwise, the GO/TO is essentially compliant once it develops the CAP and has no other requirement to make certain the relay does not trip during a stable power swing. Having a CAP implementation Requirement ensures the GO/TO mitigates potential tripping during a power swing. The CAP allows the entity to determine its own timeline for completing the work.

As a final matter before discussion assignments, future meetings, etc., the team reviewed their original Needs, Goals, and Objectives (NGO) to make certain the draft standard achieved the desire outcome. The team agreed that all goals in the NGO were achieved.

2. Review of the schedule

Mr. Barfield advised the team they can remove the second week of June for an in-person meeting off of their calendars, but to retain the third week (June 16) based on when he expects to obtain Standards Committee (SC) approval for the initial posting and based on the staging of the posting of other projects. If the posting occurs earlier, then the team may revert back to the previous week in observance of the compressed schedule.

3. Action items or assignments

Team –

- Block out the week of June 16 for an in-person meeting. Do not book travel until the official announcement is distributed.

Mr. Barfield –

- Get with Compliance on the audit approach to the Requirement that has no time period.
- Discuss with staff the use of timing in the requirements (separate or together).
- Develop a draft VRF/VSL document.
- Develop a draft Implementation Plan.
- Develop a draft Measures.
- Complete the Response to Directives and Issues.

Mr. Tackett – Check availability for meeting at MISO the week of June 16

Mr. Middaugh - Check availability for meeting at Tri-State the week of June 16

Mr. Jones –

- Screening guideline text for the Application Guidelines
- Determine if a tool can be developed to screen the Elements under scrutiny.

Application Guidelines

- R1 – Mr. Tackett

- R2 – Mr. Jones and Mr. Youngblood
- R3 – Mr. Middaugh
- R4 – Mr. Rodriquez and Mr. Schmall
- R5 – Mr. Middaugh
- R6 – Mr. Barber
- R7 – Mr. Barber

4. Next steps

Consider Mr. Youngblood's comments about the standard's Implementation Plan when drafted. Mr. Youngblood provided email comments explaining that he envisioned the implementation of the proposed standard being similar to the NERC adopted PRC-025-1 – Generator Relay Loadability standard. For example, PRC-025-1 used an implementation time period based on the implementation of the approved MOD-025-2 standard. The PRC-025-1 standard required the generating unit output to be known and MOD-025-2 was the verification of that output. It would have been practical to base PRC-025-1 calculations on assumed values rather than known or verified generating output. Mr. Barfield suggested that PRC-026-1 implementation could be triggered based on when a GO verified its output and models in order to have the most accurate analysis.

5. Webinar topics

- Tentative webinar first week of May pending the approval to post the standard in middle April
- How to deal with changes in the system and if an Element is no longer challenged by a power swing
- How to limit the breath of study for a disturbance (e.g., N-17)
- How the team simplified the scope (e.g., reduced the burden)

6. Future meeting(s)

Conference Call, Tuesday, April 8, 2014 | 2:00-4:00 p.m. Eastern – Goal to draft the Application Guidelines.

Conference Call, Wednesday, April 9, 2014 | 1:00-5:00 p.m. Eastern (includes a 30 minute break) - Goal to finalize all draft documents for quality review, provide to Standards Committee for approval to post for an initial 45-day comment period and ballot in the last 10 days of the comment period.

Tentative In-person meeting the week of June 16, 2014 pending the posting date at either MISO in Carmel, IN (Indianapolis) or Tri-State G&T in Westminster, CO (Denver).

7. Adjourn

The meeting adjourned at 12:08 p.m. Eastern on Thursday, April 3, 2014.

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-1**
3. **Purpose:** To ensure that relays do not operate in response to stable power swings during non-Fault conditions.
4. **Applicability:**

   4.1. Functional Entities:

   1.2.1 Generator Owner that applies protective relays at the terminals of the Elements listed in Section 4.2, Facilities.

   1.2.2 Planning Coordinator

   1.2.3 Transmission Owner that applies protective relays at the terminals of the Elements listed in Section 4.2, Facilities.

   1.2.4 Transmission Planner

   4.1. Facilities: The following Bulk Electric System (BES) Elements:

   1.2.1 Generating units.

   1.2.2 Transformers.

   1.2.3 Transmission lines.

5. **Background:**

   This Phase 3 of a three-phased approach is focused on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. The March 18, 2010, FERC Order No. 733, approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and another a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives and establishes the three-phased approach to standard development.

   Phase 1 focused on making the specific modifications to PRC-023-1 and was completed in the approved Reliability Standard PRC-023-2, which became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability which is currently awaiting regulatory approval.

This Phase 3 of the project focuses on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. This Reliability Standard will establish requirements aimed at preventing protective relays from operating unnecessarily due to stable power swings by requiring the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phase-out relays that cannot meet this requirement.

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner in consultation with its Planning Coordinator, Reliability Coordinator, and Transmission Planner shall, once each calendar year, identify generation and transmission Elements that meet any of the following criteria: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

Criteria:

1. Elements located at or terminating at a generating plant, where a generating plant stability constraint is addressed by an operating limit or a Special Protection System (SPS) (including line-out conditions).
2. Elements that are associated with a System Operating Limit (SOL) that has been established based on stability constraints identified in system planning or operating studies (including line-out conditions).
3. Elements that have tripped due to power swings during system disturbances.
4. Elements that have formed the boundary of an island during an actual system disturbance or within an angular stability planning simulation.
5. Additional Elements utilizing protective relays that are challenged by stable power swings in Planning Assessments.

M1. Text

Rationale for R1: The consultation with the other entities in this requirement raises awareness and provides an approach for the relay owner to obtain the Elements that may be or are challenged by power swings. The criteria is based on the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013, which recommended a focused approach to determining those Elements. The annual performance of the Requirement coincides with the annual Planning Assessment cycle.

R2. Each Transmission Owner and Generator Owner shall identify the load-responsive phase protective relay(s) at the terminal(s) of each Element from the list in Requirement R1 that are susceptible to tripping in response to a stable power swing based on the following criteria: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1. A distance relay impedance characteristic, used for tripping, that falls outside the parallelogram formed in the R-X plane by the line segments that connect the endpoints of the total system impedance line to the system separation angle points on the power swing trajectory where the relay terminals are modeled at the origin

of the R-X diagram and the relay characteristic is modeled in the first quadrant of the R-X diagram:

- The system separation angle shall be at least 120 degrees where power swing blocking is not applied.
- The system separation angle shall be at least 90 degrees where power swing blocking is applied.
- All generation in service and all transmission Elements in their normal state.
- Sub-transient reactance for all machines.
- Equal magnitude sending and receiving Thévenin equivalent voltages.

M2. Text

Rationale for R2: The drafting team recognizes that asset owners that have load-responsive phase protective relays applied at the terminals of Elements that they own and have analysis tools at their disposal that allow them to analyze a relay's potential response to power swings. Criteria were developed using industry accepted limitations that should minimize the possibility of a relay tripping for stable power swings. The bullet list of items are provided to establish a graphical representation of a conservative boundary that can be compared to a relay impedance characteristic. This is to help quickly establish whether the relay is likely to trip for a stable power swing, thus eliminating the need to test the characteristic with detailed stability studies.

R3. Each Transmission Owner and Generator Owner shall, within 90 calendar days of identifying a load-responsive phase protective relay pursuant to Requirement R2, provide the Transmission Planner a list containing each Element that is susceptible to tripping in response to a stable power swing and the Disturbance(s) that led to the inclusion of the Element(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M3. Text

Rationale for R3: A time period of 90 calendar days is sufficient to complete the initial screening (R2) since it is not expected to be a burden on the entity.

R4. Each Transmission Planner shall, for each Element in Requirement R3, determine the apparent impedance characteristics of each stable power swing resulting from the simulation of Disturbance(s) that led to the inclusion of the Element(s) or resulting from the simulation of the actual event, according to Table R4. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

Table R4.	
Condition	**Action**
1. Elements located at or terminating at a generating plant, where a generating plant stability constraint is addressed by an operating limit or a Special Protection System (SPS) (including line-out conditions).	Simulate the event that triggered the implementation of the operating limit or the SPS with the operating limit enforced or the SPS simulated.
2. Elements that are associated with a System Operating Limit (SOL) that has been established based on stability constraints identified in system planning or operating studies (including line-out conditions).	Simulate the event that triggered the implementation of the SOL with the SOL enforced.
3. Elements that have tripped due to power swings during system disturbances.	Simulate the disturbance, and if unstable, modify the event to obtain a stable power swing.
4. Elements that have formed the boundary of an island during an actual system disturbance or within an angular stability planning simulation.	Simulate the disturbance that formed the boundary of an island (whether actual or planning), and if unstable, modify event to obtain a stable power swing.
5. Additional Elements utilizing protective relays that are challenged by stable power swings in Planning Assessment.	Simulate the condition(s) that challenged protective relays in Planning Assessments.

M4. Text

Rationale for R4: The drafting team asserts that apparent impedance characteristics resulting from simulated Disturbances must be determined to assess the response of protective relays to stable power swings. The drafting team developed Table R4 to provide direction on the specific Disturbance simulations needed to obtain the apparent impedance characteristics. The drafting team assigned the responsibility for developing those impedance characteristics to the Transmission Planners because they maintain the models and tools that have the capability to develop the apparent impedance characteristics of each stable power swing.

R5. Each Transmission Planner shall, within 90 calendar days of receipt of the list of Elements pursuant to Requirement R3 provide the apparent impedance characteristics of each stable power swing determined in Requirement R4 to each Transmission Owner and Generator Owner that owns load-responsive phase protective relays applied at a terminal of the corresponding Element. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

M5. Text

Rationale for R5: The drafting team recognizes that the Protection System owners need the apparent impedance characteristics so that the load-responsive phase protective relays can be evaluated to determine if they will be challenged by the power swing. A time period of 90 calendar days is sufficient to complete since the initial screening (R2) is expected to reduce the number of Elements to evaluate (R4).

R6. Each Transmission Owner and Generator Owner shall, within 90 calendar days, perform one of the following three options for each of the apparent impedance characteristics received pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

1. Demonstrate that the existing Protection System is not expected to trip for the provided apparent impedance characteristics.
2. Develop a Corrective Action Plan (CAP) to either:
   a. Revise the Protection System settings so that the Protection System is not expected to trip for the provided apparent impedance characteristics, or
   b. Modify or replace Protection System components so that the Protection System is not expected to trip for the provided apparent impedance characteristics.
3. If option 1 or 2 will not achieve dependable fault detection or required out-of-step tripping, obtain the agreement of the Planning Coordinator, Transmission Planner, and Reliability Coordinator that Protection System tripping for the provided apparent impedance characteristic is acceptable.

M6. Text

Rationale for R6: This requirement ensures the relay owner's equipment is capable of distinguishing between stable power swings and faults. Meeting one of the three options in Requirement R6 assures that the reliability goal of this standard will be met. Options 1 and 2 address reducing the risk of relays operating during stable power swings. Option 3 is provided to strike a balance between security and dependability for cases where tripping on stable power swings may be necessary to maintain the ability to trip for unstable power swings or faults; however, agreement is required by others that tripping is acceptable. A time period of 90 calendar days is sufficient to complete one of the three options in Requirement R6 based on the initial screening (R2) and that the CAP (R7) has its own established timetable.

R7. Each Generator Owner and Transmission Owner shall implement each CAP developed in Requirement R6, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M7. Acceptable evidence for Requirement R7 may include, but is not limited to, the following documentation (electronic or hard copy format): dated records that document the implementation of each CAP and the completion of actions for each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R7: The CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.