Individual or group. (83 Responses)
Name (52 Responses)
Organization (52 Responses)
Group Name (31 Responses)
Lead Contact (31 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (19 Responses)
Comments (83 Responses)
Question 1 (51 Responses)
Question 1 Comments (64 Responses)
Question 2 (55 Responses)
Question 2 Comments (64 Responses)
Question 3 (58 Responses)
Question 3 Comments (64 Responses)
Question 4 (55 Responses)
Question 4 Comments (64 Responses)
Question 5 (54 Responses)
Question 5 Comments (64 Responses)

Individual
Jim Watson
Dynegy
Yes
Yes
No
Perhaps R1 could be reworded to answer the following question: "If an entity registered only as a GO owns relays that trip the generator alone (and not relays detecting a fault on any transmission lines), does this Standard apply?”
Yes
Yes
Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Florida Municipal Electric Agency
Group
US Bureau of Reclamation

Joe Uchiyama
JOe Uchiyama
Yes
1)We agree to isolate the least number of power system elments during a fault. However, PRC-027 & PRC-001 are lack of a statement which elements be reviewed by entities. It seems like it is upto utilities to decide wchich elements to be reviewed and studied for. For the comliance purpose, how does Autority judge the reviews/documents were meeting PRC-027? 2) Pg. 2- Definitions of Terms Used in Standard- “Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.” – The Interconnected Element definition should be expanded upon and attached figures added showing what is and is not an interconnected element relative to the generator and generation owner. 3) Page 2 – The term “Functional Entities” as used in the definitions for “Interconnected Element” should include a definition. 4) Pg. 4- A.5 –“Other Aspects of coordination of Protection Systems addressed by other Projects: Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following existing standards or current projects.” – The paragraph should be more specific as to whether the “fault clearing” referenced is used for primary transmission line protection or primary generator/generator step-up transformer protection. Namely, does what is addressed in PRC-027-1 exclude fault clearing used for primary generator/generator step-up transformer protection? 5) Pg. 8- R3.- 3.1- “• New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios.”- The sentence should be changed to read- “• New installation, replacement with different types, or modification of: fault clearing protective relays or protective function settings, related communication systems, related current transformer ratios and voltage transformer ratios.” 6) Last paragraph on page 26 starting with “Protection Systems installed to detect faults on the BES…” has some great examples (especially the last sentence of that paragraph) of the intent of PRC-027. I think it would be useful to move or copy this type of verbiage to the beginning of the document and use it in the definitions to accomplish what Pete has commented on below.
Yes
Yes
Yes
Yes
Individual
Michelle R. D'Antuono

Ingleside Cogeneration LP
Yes
Ingleside Cogeneration agrees that it is appropriate that PRC-027-1 is self-contained throughout. Even though the Purpose statement is not necessarily mandatory and effective, it is conceivable that the previous version would lead a Compliance Enforcement Authority to require evidence that fault studies account for relay performance governed by other NERC standards. This could result in the assessment of two penalties for the same violation – a double jeopardy condition that should be avoided.
Yes
No
Ingleside Cogeneration, like many other Generator Owners, does not typically perform fault studies unless we have made material changes to our transmission system interconnection. Even then, we provide modeling data to the appropriate Transmission Owners and Transmission Planners, who execute the assessments on a Regionally-standardized platform. We are not convinced that we can add value to this process – other than to demonstrate that the information required by the TO and TP was provided, and the study took place. In our view, the requirement should clearly accommodate this working arrangement. As it reads now, it seems like both the GO and the TO must perform separate assessments. The extra costs that we will incur to commission external consultants is difficult to justify when there are so many other pressing priorities (e.g.; cold weather preparedness).
No
Ingleside Cogeneration still holds to the position that a dispute resolution process needs to be defined should we reach an impasse with the TO. R4 still requires that both parties “accept” the proposed change – which means that one or the other could unreasonably demand an Protection System-related expenditure without any need to demonstrate that a corresponding reliability benefit will be realized. It is not apparent to us that this situation is already addressed in NERC’s Rules of Procedure, which ultimately is the governing document for continent-wide Reliability Standards.
Group
Northeast Power Coordinating Council
Guy Zito
No
By restricting the coverage to “… Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults” there is a significant gap in reliability created by the exclusion of elements such as loss of field, out-of-step, etc. An incomplete Protection System Study negates all the work needed to satisfy this Standard. Perhaps through referencing the NERC technical reference document entitled “Power Plant and Transmission

Protection Coordination", there could be a reference to which protection elements are going to be covered in this Standard and likewise what Standards will cover the protection elements not covered by this Standard. As identified by the Drafting Team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of generator loss of excitation protection settings or out of step relaying during a fault condition – is that meant to be covered in this Standard or elsewhere? The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions, not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. PRC-027 should provide the similar effective vehicle to convey at least the "what" for Protection System coordination during faults between entities, and will allow entities to perform and document consistent Protection System Studies. The term "coordination" is not well defined. Does it mean ensuring owners of all terminals of a line, transformer, etc. are aware of each other's protection system design and settings, especially when the design, settings, and physical system changes? Developing a formal definition to be included in the NERC Glossary should be considered.
No
In the proposed definition of Interconnected Element "Functional Entities" is capitalized even though it is not in the NERC Glossary.
No
Due to the extensive documentation, coupled with the collaboration between entities associated with this requirement, NPCC believes 60 months is a more appropriate time frame to comply. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. An alternative to the "static" time frame discussed above, which would also be acceptable, would be to base the timeframe on a formula that factors in the number of interconnected power system elements that the entity must contend with.
No
This change is more ambiguous than reach agreement. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to confirm acceptance?
Yes
We agree with the change. However, we are adding a comment on the VRFs. The VRFs should be High, not Medium. There are similar requirements in PRC-023-2 Transmission Relay Loadability, and TPL-001-2 Transmission System Planning Performance Requirements which have a High VRF. Also, from the Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 — Protection System Coordination for Performance During Faults, the FERC VRF G4 Discussion reads "Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk

Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC's definition of a Medium VRF." Poor protection system coordination during a disturbance can create severe system conditions faster than Operators can respond to them, leading to system instability or a cascading failure. These circumstances are consistent with the NERC definition of a High VRF.
Individual
Andrew Z. Pusztai
American Transmssion Company, LLC
Yes
However, ATC recommends that the Purpose statement in the Standard be modified by adding the word "intended" : "To coordinate Protection Systems for Interconnected Elements, such that the least number of intended power system Elements are isolated to clear Faults."
No
The Interconnected Element definition should be expanded to clarify that PRC-027 is applicable to only BES Elements as demonstrated in Figure 4 of the Standard's Application Guidelines on pg. 27. • ATC recommends that the SDT please modify the definition of Interconnected Element as follows: "A Bulk Electric System Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity" If "Functional Entity" is used and capitalized in the definition above, the term should be defined in the standard or be made part of the "Glossary of Terms Used in NERC Reliability Standards." Furthermore, NERC's "Reliability Functional Model version 5" states: "The following terms are used in the Functional Model and do not appear in the NERC Glossary. Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function."
No
The SDT states that there is no evidence of wide spread misoperation due to lack of coordination. However, R1 requires a utility to establish an evidence package of legacy coordination that predates PRC-001's effective date. While 48 months is an improvement to PRC-027, that timeframe still imposes a significant burden on utilities, especially those that are not vertically integrated. ATC recommends that the SDT consider changing the implementation period for R1 from 48 months to 72 months.
Yes
Yes
Group
ATCO Electric
Rowell Crisostomo

No
ATCO Electric (AE) has an existing protection review program that runs on 5 year cycle. Each year, AE review approximately 20% of AE’s transmission system to ensure the protection is in place or needs adjustment. Can the drafting team increase 48 month duration to 60 months?
Additional comments from AE that does not fit any specific question: (1) Timelines: There are too many hard timelines that aren’t consistent between individual requirements (24 months, 6 months, 90 days, 30 days, agreed upon time frame, prior to implementation, etc.). Keeping track of these timelines and evidence gathering will take considerable time and effort. Can the drafting team reduce the amount of timelines to make this standard manageable? Can the drafting team anticipate how to audit this standard during the standard development process? (2) There are requirements referred to other requirements and vice versa. Can the drafting team not to refer the requirements back and forth? Can the drafting team anticipate how to audit this standard during the standard development process?
Individual
Si Truc PHAn
Hydro-Quebec TransEnergie
Agree
NPCC
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
The language in the Statement of Purpose needs to be reworded. The phrase “such that the least number of power system Elements are isolated to clear faults” may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the

above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement that "the least number of power system Elements are isolated to clear faults". The language used in the proposed definition of Protection System Study is better; using the phrase "demonstrates ... Protection Systems operate in the desired sequence for clearing faults". The problem here is who determines what is the "desired sequence"? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the "desired sequence" for clearing faults? The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point. In conclusion, we suggest re-wording the Purpose to read: "To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence for clearing Faults." This statement is consistent with the stated definition of the Protection System Study, on which the measures of this standard are based.
Yes
No
Each owner should already possess information demonstrating that their protective devices are set to "coordinate" with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal "coordination study" in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 48 month requirement.
No
We find that changing the wording from "confirming acceptance" to "reaching agreement" does little to address the root problem associated with mandating mutual agreement. We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns

outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the “Protection System Study” and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.
Yes
We agree with this change. However, we have several other comments concerning this standard in addition to those expressed in response to Questions 1 thru 5. Usually there is a space on the comment form to enter these additional comments. Absent one, we offer these additional comments as an addendum to Question 5. 1) Requirement R2: The phrase “Facility associated with an” contained in R2 is confusing and unnecessary and should be eliminated. R2 should simply read “For each Interconnected Element on its System, the Transmission Owner

shall:” 2) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term “interconnecting bus” and replace it with the phrase “point of interconnection between the Entities.” The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical “bus”, but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a “bus”, the term “interconnecting bus” has no physical meaning. 3) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). 4) The SDT states that “the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays”. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of “the appropriate use of time delays in relays” in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS’s during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are “properly coordinated”; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is

widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, we believe PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. We urge the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives.
Group
Western Small Entity Comment Group
Steve Alexanderson P.E.
Yes
Yes
No
The comment group agrees that Protection Systems associated with Interconnected Elements must be coordinated. However, the reliability goal should be strictly focused on documenting the associated owners (parties) are cooperating, and in agreement with protection settings to achieve proper coordination. A requirement to have a documented Protection System Study completed will not improve on a simple statement from the parties that proper coordination has been agreed upon. Provision of a Protection System Study as compliance evidence (in whole or a summary) implies recourse to check its completeness or accuracy. For complex systems, this is very subjective. However, the Standard as written intends to make no effort to verify the completeness or accuracy of a Protection System Study; the intent is to simply verify that it exists. Since the Protection System Study is not subject to review, its production as compliance evidence is nothing more than added bulk.
Yes
Yes
1. The comment group has no comments regarding this question. 2. This form provides no general comment area, so we are providing our additional comments here. We referenced the WECC Position Paper in the last round of comments, but now see that WECC did not submit comments. We urge the SDT to take a look at the paper. We received our copy from steve@wecc.biz . We can also forward a copy if an email address is provided. For the team's convenience, here is the relevant text: "WECC staff and WECC subject matter experts have reviewed the proposed standard and agree with the purpose of the standard. WECC staff and WECC subject matter experts agree that Protection Systems must be coordinated. However

some subject matter experts believe that the proposed standard requires more documentation than is necessary and that the requirement to provide a hard copy or an electronic copy of each Protection System Study is administratively burdensome and not reflective of the intent of Results Based Standards. These subject matter experts believe that evidence that studies are coordinated and that entities have agreed to the results of System Protections Studies is adequate." We see that the SDT responded to Salt River Project's and other's similar concerns regarding hard copies by stating that that only summaries are needed, but we still see the standard as overly burdensome compared with the possible benefit. Tennessee Valley Authority, Dominion Power, Southwest Power Pool, the Nebraska Public Power District, Dairyland Power Cooperative, the Bonneville Power Administration, and the SERC Protection and Control Subcommittee provided some specific suggestions to reduce documentation burden which were all rejected. We urge the SDT to review these recommendations again.
Individual
NICOLE BUCKMAN
ATLANTIC CITY ELECTRIC COMPANY
Agree
Pepco Holdings Inc and Affiliates
Individual
Don Jones
Texas Reliablity Entity
Yes
Yes
The SDT may want to consider additional language for the Protection System Study definition, to clarify that the study demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults as well as clear the Faults within the maximum time frame defined by the Transmission Planner in order to maintain System Stability. Another consideration would be that the study incorporates all of the applicable Fault contingencies (Category B and C) as defined in the NERC Reliability Standards (TPL-002 and TPL-003) or any Regional standards.
Yes
No
TRE agrees with the need to notify the Facility Owner of the proposed changes. However, if the receiving entity does not agree with the proposed changes, there needs to be a venue to reach consensus. The receiving entity should be able to suggest changes based on technical rationale to resolve the disparities. A provision for dispute resolution needs to be provided. TRE suggests re-wording R4.2 to – "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, notify the Facility owner(s) associated with the affected Interconnected Element. If consensus cannot be reached on the proposed Protection System(s)

changes, each entity shall document the technical rationale for its position on each disputed issue prior to implementation."
Yes
OTHER COMMENTS (not responsive to any specific question asked above): R2.2: We suggest a minor change "...indicates a deviation in ***single line to ground or 3-phase*** Fault current of 10% or greater ...." R3.1: Based on recent work by the Protection System Misoperation Task Force (PSMTF), changes in logic settings should also be included (e.g. directionality V/Q logic, trip equations, carrier echo logic and coordination timers, carrier dip switch settings, etc.). We would suggest modifying the first bullet to say"...modification of: protective relays or protective function or logic settings, communication systems,...." The SDT may also want to consider adding an item to the list - "Changes to the transmission system topology that change the equivalent impedance or fault current."
Individual
Patrick Brown
Essential Power, LLC
No
The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, "the entity performing the Protection System Study [for R1]," but the standard provides no indication of who this should be. This responsibility is simply assigned to, "Each Transmission Owner, Generation Owner, and Distribution provider." The obligation placed on GOs by use of the word "each" in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO's system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO's equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don't matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO's system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should say so, rather than pulling in all GOs regardless of whether or not it makes any sense for them to be involved. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in

the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Fnctional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO’s system.
No
The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
Yes
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Mark Yerger
Potomac Electric Power Compan
Agree
Pepco Holdings Inc and Affiliate
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
No
Suggest replacing Protection System Study with Coordinated Protection System Study.
Yes
Yes

No
IID believes the affected entity need to demonstrate it received notification.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
The purpose should mirror the objectives of the Protection System Study: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” There are cases where industry practice is to “overtrip”, for example, for a tapped non-BES distribution transformer fault by tripping BES line breakers and reclosing. Also it may be a common practice to use zone 1 extension or acceleration schemes. There can be good reasons for intentionally tripping more than “the least number of Elements to clear a Fault”. The Purpose statement as currently written is in conflict with these valid industry practices, and needs to be modified.
Yes
No
We strongly believe that 60 months would be a more achievable time frame to study the many interconnections that an entity may have. This will also allow Generator Owners the time needed to gain the resources required to perform these studies, since they may not be presently so equipped. As stated by the drafting team in the rationale for R1 there is no evidence of wide spread mis-coordination of Protection Systems associated with Interconnected Elements. It would also be helpful to provide a better description of what is required to be included in a Protection System Study. For example, is the study required to include pilot scheme timing and element coordination, breaker failure coordination, coordination under minimum and maximum fault current cases, etc?
No
The current draft standard lacks any clear responsibility for performing the complete Protection System Study, especially if the interconnected parties cannot accept or reach an agreement. The recommended change is to make the Transmission Owner accountable for the overall Protection System Study, at least at the Generator-Transmission interconnections. The other entities such as Generator Owners should be responsible to provide the necessary data required for the overall study. This makes the most sense based on limited resources and capabilities, as well as access to all data. This is especially true for independent Generator Owners that operate in the deregulated market. It is not feasible to make all entities somehow responsible for the study.
Yes
Individual

Scott Miller
MEAG Power
Agree
Essential Power, LLC
Individual
Wryan Feil
Northeast Utilities
Agree
Northeast Power Coordinating Council Inc. (NPCC) 1040 Avenue of the Americas 10th Floor New York, NY 10018
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Agree
NPCC, the Northeast Power Coordinating Council
Individual
Thad Ness
American Electric Power
Yes
No
AEP recommends replacing all references to "generator Protection Systems" with "Generator Owner equipment that provides backup system protection", and suggest adding language to the standard for clarification. The scope of Generator Owner Protection Systems applicable to this standard is not clear from the verbiage within the standard or the definition of Interconnected Element. AEP believes that the SDT did not intend to require the GO to include all generator Protection Systems under this standard (as shown in Figure 2 on page 25 and Figure 5 on page 28 of the clean draft), but instead meant to limit the scope of relaying to be coordinated to only the Generator Owner equipment that provides backup system protection. AEP agrees with the definition of Protection System Study, however, we disagree with using the acronym PSS within the standard as PSS is also the recognized acronym for Power System Stabilizer. Usage of this acronym (for example, in the Process Flow Chart) would cause unnecessary confusion.
No
AEP believes that 48 months to complete a Protection System Study is too short of a time frame, especially for Interconnected Elements which do not have an existing study. NERC's rationale for R1 states that "the drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." If this is the case, then there should be no issue with extending this

timeframe. AEP believes that 72 months is a more reasonable timeframe for the following reasons: * The Transmission Owner will need to complete their own studies, as well as provide data to the entities they interconnect with (i.e. TO’s, GO’s, and DP’s). This dependency would effectively shorten the amount of time the functional entity has to complete their studies to less than 48 months. * Before the work of the first bullet point above can be completed, entities must develop an agreed-upon list of Interconnected Elements and associated owners of the Protections System(s) associated with each Element. Once again, the time required to complete this task erodes into the entire time allowed to perform the study. In short, much of this work must be sequentially rather than in parallel, further justifying the need for an increased timeframe. * The resources needed to complete the required studies will also be impacted by a number of other standards currently in draft including: PRC-006-1, PRC-019-1, PRC-024-1, PRC-025-1 and PRC-004-3. The work required to perform both the proposed studies of this standard, as well as the other standards listed above, requires a Subject Matter Expert possessing a specific skillset gained from years of protection experience. Due to the limited number of such SMEs, industry will be very challenged in meeting all the proposed requirements given the limited number of such resources. In addition, the demand for qualified outside resources might be greater than their actual availability due to the time constraints involved.
Yes
Yes
Because the comment form provides no section to provide “general comments”, AEP offers them below. AEP would like to inform the drafting team that our negative vote on this standard is primarily driven by a) the lack of clarify in regards to its scope (as discussed in the response to Q2) and b) the timeframe allotted to perform the Protection System Study (as discussed in the response to Q3). It would be more appropriate for R 1.1.1 to be included in the implementation plan, rather than embedded within the standard itself. The proposed standard is difficult to follow, in the way that it jumps back and forth among requirements. We would encourage any changes which might increase the readability of the proposed standard.
Individual
Daniel Duff
Liberty Electric Power LLC
No
Functional entity is not defined. System Studies should be defined as "a study performed by a TO that demonstrates.....etc."
No
R1 should not apply to GOs. GOs are not allowed to have the TO information needed for a system study under market rules.
Yes

Yes
Individual
Nazra Gladu
Manitoba Hydro
Yes
Although Manitoba Hydro agrees with question 1, we have the following general comment: (1) The purpose statement and R1.2 refers to Elements within the 'power system' which is not defined, while the 'Facilities' refers to 'Elements of the BES' and the 'Requirements' reference Interconnected Element on a particular entities' 'System' or 'transmission system'. Should these be consistent or has this been done purposefully?
Yes
Although Manitoba Hydro agrees with question 2, we have the following general comments: (1) Please clarify why definitions are to remain with standard upon approval and not be moved to the Glossary. Are these definitions applicable only to this particular standard? If this is the case, this could lead to uncertainty if similar terms are going to be used or defined elsewhere. (2) Compliance 1.1 – The word 'Compliance' in the first line should not be capitalized and (CEA) should follow the word 'authority'. Since 'Regional Entity' is a defined term, 'Entity' needs to be capitalized. (3) Compliance 1.2 – The second paragraph should begin with 'Each', not 'The'. We suggest that the reference to an 'Interconnected Facility' in the second paragraph should be changed to 'a Facility associated with an Interconnected Element' to make it consistent with the rest of the standard, including the third paragraph of 1.2.
Yes
Although Manitoba Hydro agrees with question 3, we have the following general comments: (1) R2, 2.1.1 – Reference to the Protection System Study should be the most recent Protection System Study to be consistent with the rest of the requirement and the use of the word 'available' is a little problematic. What if no study exists? As we read it, the requirement to do a study is within 48 months of the effective date of the standard, while the requirement to do a short circuit study is at least every 24 months. If the Protection System Study is not available, is there no requirement to do the short circuit study? (2) R2, 2.2 – For clarity, we suggest rewording the first sentence to read 'Within 30 calendar days after identification, through the calculation performed pursuant to Requirement R2, Part 2.1.2, of a deviation in…' (3) R3, 3.1 – No time frame is given and it is unclear as to whether these details are to be only for proposed or future changes or additions, or whether it can be 'notice after the fact' (when read with the remaining requirements, it would be assumed it is 'prior notice', but that's not clear on the face of this part 3.1). In addition, should 'facilities' be capitalized in 3.1? Also, there needs to be consistent references to 'changes and additions' or just 'changes' within this R3 as currently there are references to both made. (4) R3, 3.2 – We suggest moving the time frame to the start of the Part for consistency with the drafting of other Parts and for ease of reading. (5) R3, 3.3 –

We believe that the timeline is incomplete. Assuming that the timeline is meant to be 'within 30 calendar days of the (proposed?) changes or additions being made'. (6) VSLs/VRF table: R1, R3 – For consistency, the references should read 'less than or equal to 10 calendar days' instead of '10 calendar days or less'. (7) VSLs/VRF table: R4 – All of the references to 4.1 appear to be incorrect because 4.1, as currently drafted, does not require confirmation of acceptance of the summary results.
No
(1) R4, 4.2 – The concept of 'accept' the changes are problematic. We are unclear as to what exactly this means? Is it something more than acknowledging that the changes are occurring? Does it go so far as 'agreement' with the changes? What happens if the owner does not 'accept' the changes? (2) R4, 4.1 – For consistency with wording the in R3, 'planned change' should be 'proposed change' or 'addition'.
Yes
Although Manitoba Hydro agrees with question 5, we have the following general comments: (1) M1 – The word 'that' in the third line should be deleted and we believe that the words 'is dated documentation' are missing after 'Acceptable evidence for Requirement R1, 1.2. (2) M3 – For consistency, the word 'formula' should be replaced with calculation in Requirement R2, 2.1.2. (3) M4 – For clarity and consistency with the other Measures, we suggest rewording the opening sentence to read 'Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) demonstrating that the updated Fault current values were provided within….'. (4) M5 – The wording of this section does not match the wording of the requirement. The words 'in hard copy or electronic file formats' should follow the word summary, not after the word settings.
Group
Midwest Reliability Organization NERC Standards Review Forum
Joseph DePoorter
Yes
Yes
No
The NSRF recommends that this Standard be filtered through the paragraph 81 criteria. If not, the NSRF recommends the following items. Although supportive of the extended timeframe in R1, the NSRF is concerned that the proposed Part 1.2 is overly prescriptive. Considering the sheer quantity of microprocessor relay settings that could potentially be reviewed as part of a Protection System Study, having to provide associated owner(s) the results of every protective relay setting reviewed would be unnecessarily burdensome with little benefit to reliability. Recommend the drafting team revise Part 1.2 to require entities to only provide information related to settings being proposed for change and have all other settings be made available upon request. Please clarify the application of R1, Part 1.2 in the event that both ends of the

Interconnected Element are owned by the same entity. In consideration that final settings and internal documentation would provide proof that everything was looked at accordingly, would the entity still need to develop and distribute a summary internally as well? Recommend revising Part 1.2 to only require functionally separate entities to provide documentation of the results of the Protection System Study. Rather than specify the details to be shared as a result of a Protection System Study, recommend Part 1.2 be modified to remove "power system Elements to be isolated, contingencies evaluated" as a minimum requirement. Having entities share their evaluation methods with other Entities appears to be unnecessary administrative work. Considering that it is the responsibility of the individual entity to perform their studies correctly, another entity should not have to worry about, nor does it have the responsibility for keeping tabs on, whether an external study was done to a single or double contingency level, what external Facilities become isolated, etc. Additionally, the NSRF is concerned with the phrase "Fault current used" as it applies to R1, Part 1.2. In consideration that Fault current values do not necessarily mean that two entities are using like models, recommend a comparison of boundary equivalents be used instead to ensure that the models are comparable between entities. If not, entities would potentially be sharing every value for every iteration to ensure like models. Suggested revisions to R1, Part 1.2 in support of the above comments are as follows: 1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with Interconnected Element(s) that include two or more Registered Entities, a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, proposed revisions to the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, boundary equivalents at necessary buses Fault currents used, any issues identified, and any additional revisions proposed). If existing documentation does not include enough detail to meet the requirement for an acceptable Protection System Study, utilities will be forced to add to the existing documentation for compliance purposes even though the existing settings coordination is adequate. This will place additional compliance burden on utilities while not necessarily improving reliability. Since there is no evidence of widespread mis-coordination of Protection Systems associated with Interconnection Elements, it would seem reasonable to have this standard apply to any changes made to an existing Protection System or all new Protection Systems.
No
R4, Part 4.2: In consideration that R4, Part 4.1 already requires entities to review the results of a Protection System Study and provide any related feedback, recommend Part 4.2 be removed from the standard. Without additional guidance within the standard specifying the timeframe in which an entity must provide its confirmation, the entity implementing the planned change could potentially be left waiting indefinitely for confirmation despite the study already being reviewed and accepted as part of Part 4.1. If part 4.2 is not removed, recommend that additional guidance be provided concerning time frames (90 days?).
In addition to the previous comments outlined above, the NSRF offers the following comments for the drafting team's consideration. Recommend the timeframes in R1.1.1 and R2.1 be stated in calendar years. The NSRF is concerned that a utility would be found in violation of this standard if one study was done in February of 2012 and the next one in March 2014 based on

the current wording. The intent of a results-based standard is not to have these types of technicalities built into them. An entity cannot study a part of the system that they do not own. The examples at the end of the draft in the Application Guidelines appear to imply that they should. Settings should be obtained from remote ends of a tie line only to be used in conjunction with studying the settings for which an entity has direct control. If an entity can't issue setting changes for a relay, then the entity can't study it to see what the settings should be. If both ends need adjustment then an iterative coordination back and forth between Entities should be performed. The majority of utilities would not feel comfortable accepting an external entity's settings changes for their own equipment. Recommend additional wording be added to the Application Guidelines to the further clarify the drafting team's intent. R2, Part 2.1.1: Recommend R2, Part 2.1.1 be revised to only require short circuit values be 'studied' at buses for which the entity in question specifically owns. For Interconnected Facilities between two entities, fault current values should be 'requested' by the neighboring utility. This would be beneficial to ensure that both entities are comparing models to keep them as up to date as possible. Better yet are boundary equivalents as discussed in previous comments. R2, Part 2.2: Similar to our previous comment for R1, Part 1.2, the proposed language in Part 2.2 appears to indicate that internal Interconnected Elements would require additional documentation and notification beyond what is necessary. This should only be required of Interconnected Elements in which there are two or more owners. Proof of study should be adequate for internal situations. 2.2 Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element, that include two or more Registered Entities, the updated Fault current values (Iscs).
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Agree
Support both the previous comments of Bonneville Power Administration and the comments of the Western Small Entity Comment Group
Individual
Kayleigh Wilkerson
Lincoln Electric System
Agree
MRO NSRF
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes

Yes
Under figure 2 in the application guidelines the example need to be reviewed and text added to clearly identify the intent of the drafting team. For example is the scope for Generator Owners in figure 2 just the backup system protection for the Transmission Owners system? It's not clear in the examples given. This issue is also present in figure 5. We agree that if the scope is just for the backup system protection it is ok but the wording does not clearly state this. Also using PSS as an acronym for Protection System Study could be confused in the flowchart of this standard with power system stabilizers since there isn't any text to spell out that it is referring to Protection System Study.
No
We are concerned that 48 months could still not be sufficient for these studies. We would ask that the team consider 72 months. There is a concern that with all the companies having new standards to comply with, the Transmission Owners/Generation Owners are being overloaded and have the same resources.
Yes
Yes
Group
National Grid and Niagara Mohawk (A National Grid Company)
Michael Jones
Yes
Yes
No
How would "fault currents used" be presented for coordination of distance relays ? Also if the above items must be included, at a minimum, they need to be enumerated in requirement R1.
No
It is not clear where the old text "reach agreement" and the new text "confirming acceptance" were/are used. Also, "confirming acceptance" is vague in meaning.
Yes
National Grid offers the following additional comments that do not pertain to Question 5. The comments are included here since the Comment Form did not have an additional question concerning if we had additional comments. 1. Page 4: Other Aspects of coordination of Protection Systems addressed by other Project needs to be included in the final standard since it delineates what is not included in this one. 2. Page 8: Para.R2.1.2 should be reworded as it allows for a series of increments in fault current each less than 10% but which when summed over a number of review periods could collectively exceed 10%. 3. Application Guidelines: a.

Page 21: "Data used to determine Fault currents…." is essentially the short circuit model and the associated data base of line, transformer and generator impedances and connections. If that what is expected then it should be so stated otherwise "data" leaves a lot open to the reader's conjecture. b. Page 25: Decision point regarding R2.1.2 has the same issue as identified above in comment 2. c. Diagrams Fig. 1, 2, 3, 4, 5: The text that goes with these diagrams is inappropriate in its assignment of responsibilities for who reviews what coordination and the change of wording from "verify" to "review" does not resolve this problem. It is a protection system owner's responsibility to coordinate their system with adjacent systems and it is the same owner's responsibility to model adjacent systems in sufficient detail to enable that owner to perform that coordination. Fig . 2, 5: The text refers to "generator protection" which can mean a wide range of protection functions such as but not limited to those related to voltage, frequency, loss of field, over-excitation and more. These were excluded on page 4 of the standard and their exclusion here should be emphasized. Fig. 3, Notes following figure 3 exclude reverse power as being a protection system installed to detect faults on the BES Transmission System. We disagree. In our system and other systems in NE reverse power was historically installed specifically to detect and clear backfeed to a faulted transmission system.
Group
Salt River Project
Bob Steiger
Yes
Yes
No
Agree with timing, but confirmation from both parties that coordination has been reviewed should be adequate evidence.
Yes
No
Receipt of confirmation should be required to confirm coordination.
Group
Bonneville Power Administration
Chris Higgins
No
The Purpose given assumes that the most important outcome of a protection system operation is that the least number of power system elements are isolated to clear a fault. While it is true that it is usually desirable to prevent parallel paths from opening, in many cases it might be

perfectly acceptable for adjacent elements to operate. BPA believes it may be more economical to have a protection system that isolates elements in addition to the faulted element if the isolation of the additional elements does not result in problems for the BES. A suggested Purpose statement that takes this philosophy into account is: To insure that separate Functional Entities properly coordinate with each other the protective systems for elements that interconnect their electrical systems so that only the intended power system elements will be isolated to clear a fault.
No
With regard to the definition of Interconnected Element, BPA believes the term should be interconnecting element, because the element is not interconnected, rather the systems of the functional entities are interconnected by the element. The point of interconnection between two functional entities is typically where two elements meet, such as between a line and a switch, and it is not a clear which element is the interconnected element. For example, suppose that a line from one entity terminates through a breaker at the bus of another entity’s substation. Which is the interconnected element, the line, the breaker, or the bus? In another example, a generator ties to a transmission providers BES through a step-up transformer. Which is the interconnected element, the step-up transformer or the transmission line? Additionally, if a distribution provider taps off of a transmission provider’s 230kV line through a disconnect switch, is the disconnect switch the interconnected element? BPA asks that the definition of Interconnecting Element be further clarified to provide the specific criteria that entities are expected to apply to come up with a consistent response in all such instances. The SDT attempted to illustrate the concept of the interconnected element through some examples in the Application Guidelines; however, the selection of the interconnected element in these examples neither follows logically from the standard nor provides the additional clarity necessary to enable industry participants to apply it in a manner that enables all users to come up with the same answers.. BPA believes the standard needs a clearer definition of an interconnected element. With regard to the definition of a protection system study, the definition given is too vague to provide a clear understanding of what is required by the standard.
No
BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short.
No
According to this standard, something as simple as changing a CT ratio must now be communicated to all interconnected functional entities and documented. The interconnected functional entities must then “confirm acceptance” of the CT ratio change before the change can be made. The acceptance must then also be documented. This level of bureaucracy is unnecessary and counterproductive. The change from “reach agreement” to “confirming acceptance” is irrelevant.
No
BPA believes that the requirements and measures are onerous and should be eliminated. The change in wording is irrelevant. Additional Comments R1.1 requires a protection system study

to be performed, but does not explain what is required for a protection system study. R1.2 lists some minimum requirements of a protection system study, but leaves many unanswered questions, for example: Which relays must be included in the study? Where are the faults to be applied? What contingencies should be applied for the study? How many buses back into the system must be reviewed? R1.1.2 introduces the term “interconnecting bus” with no definition of what it is. R2 is a requirement that pertains to each facility associated with an interconnected element. The use of the word “associated” is too vague and leaves the interpretation of this requirement wide open. In R2, the need to perform a new protection system study is based on a 10% or greater increase in fault current. Since many relays are based on impedance or differential methods, the value of fault current has no bearing on their need for a coordination review. R2, therefore, results in an unnecessary and useless burden when applied to elements protected with these relays.
Group
GP Strategies
Mary Jo Cooper
Yes
No
We do not believe that the drafting team appropriately identified the correct Applicable Functional Entities for this Standard. We also believe existing Standards could be modified to resolve any reliability gap rather than creating a new Standard. As a result, while the Purpose of this standard may seem to be reasonable, we feel that the drafting team should either 1)Change the Purpose to state “To conduct necessary studies to ensure Protection Systems for Interconnected Elements are studied, such that the least number or power system Elements are isolated to clear Faults.” And change the Applicable Functional Entities to the Transmission Planner or 2) modify existing Standards, instead, as described below. The short-circuit studies should be conducted by the Transmission Planner. From Appendix 5B of the Registration Criteria the: • Transmission Planner is the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.” • Distribution Provider is the entity that provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.” TPL-001, TPL-002, and TPL-003 already require the system studies are conducted. These Standards should be modified to include any additional studies that the drafting team feels are a gap. As noted in the drafting teams Rational for Part R2.1 “Short circuit databases are customarily updated annually so the drafting team believes 24 months provides entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.” That being said, there is no current Requirement for the Distribution Provider to provide the information to the databases so that the Transmission Planner can conduct the

studies on the Interconnection Facilities. We recommend that MOD-010 and MOD-012 should be modified to include the Distribution Provider instead. For new facilities, FAC-002-1 already requires the coordination of changes in the Facilities.
Yes
Yes
Yes
Group
Arizona Public Service Company
Janet Smith
APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
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Individual
John Seelke
Public Service Enterprise Group
No
What information comprises a Protection System Study (PSS)? In the Application Guidelines, from Figure 1 on p. 24, each owner that receives a PSS is “to review the Protection System setting” associated with the other owner’s breaker that would operate to clear a Fault on the transmission line that connects each Interconnected Element. Is this (Protection System settings) the ONLY information that needs to be transmitted in a PSS by each owner? The SDT should itemize ALL of the information it believes needs to be included in a PSS that is to be transmitted between owners of an Interconnected Element and include that information in the examples in the Application Guideline. This information should also be listed into the PSS definition, thereby defining its scope.
No
The issue is consistency in what comprises a valid PSS. For example, for "contingencies evaluated," it seems that each owner should evaluate a core set of the same contingencies as opposed to this being an owner-by-owner decision. The lack of specificity as to what is required for a PSS is the issue.
Yes
Yes
Group
Luminant
Brenda Hampton
Yes
Yes
No

Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "… Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be within 90 days or in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, or Distribution Provider." This would align with R4.1 that also provides the same time frame. The corresponding measures will also need to be modified if this language is accepted.
Yes
Yes
Individual
David Jendras
Ameren
Yes
We are voting negative for three reasons, one provided below and two are included in response to Question #3. Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all. (1) We request that the SDT replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places where it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry.
Yes
Yes
(2) Requirement R2 requires short circuit study every 24 months even though the SDT's own rationale is that other requirements will trigger Protection System Studies first. Thus we believe that R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. (3) VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." We have about 500 Interconnected Elements per our present understanding of Draft 2 definitions and guidance. We recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation.

Yes
Yes
Group
Operational Compliance
Ed Croft
Yes
Yes
Yes
It would be great if NERC provided a common format for all of us to use when providing this information
Yes
Yes
Individual
Chris Mattson
Tacoma Power
Yes
No
Where is the term Functional Entity defined? Consider changing the term Protection System Study to Protection System Coordination Study. There are two reasons for this recommendation. First, the abbreviation for Protection System Study is PSS, which is also the common abbreviation for power system stabilizer. Second, the term Protection System Coordination Study emphasizes the primary purpose of PRC-027-1: to coordinate Protection Systems.
Yes
Yes
Yes
Additional Comments: Why is there a version 4 for PRC-001 (under Version History) when the

standard being balloted is version 3 (PRC-001-3). PRC-027-1 does not appear to impose any requirements as to how quickly issues identified in a Protection System Study are addressed. It may be difficult to impose such a timeframe since some issues may just require a relay setting change, while others may require more drastic scheme modification, including design, procurement, installation, and commissioning. Perhaps requirements could be added to develop, within a specified timeframe, and then implement a mutually agreeable Corrective Action Plan. As written, it appears that an entity can be compliant with Protection System Studies that always indicate existing coordination issues, which does not completely achieve the purpose of the standard. Without a mechanism to close the loop, PRC-027-1 appears to require a lot of documentation and coordination without any guarantee that existing coordination issues will ultimately be resolved. R4.1 really only requires entities to come to terms on the Protection System Study, but does not explicitly require any other course of action on existing coordination issues. In M1, the sentence ending in “…demonstrating that the time frames specified in Parts 1.1.1 and 1.1.2” in a fragmented sentence. Also, should this sentence have “and 1.1.3” at the end? M2 is a fragmented sentence. M4 is a fragmented sentence. As written, it may be difficult to audit parts of R3.1. Some of the language seems to be subjective and implicitly left to engineering judgment. First, it is not completely clear what the drafting team intended by the wording “associated with” or how an auditor might interpret that wording. Second, please consider changing “…or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)” to “…or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s), as stipulated in the existing Protection System Study.” This should make it easier to audit this aspect of R3.1. Third, regarding the second through fourth bullets, engineering judgment will be required to determine when impedances need to be changed. For example, minor modifications could be made to a transmission line that, in a purely academic sense, could change the impedance; however, an entity may opt not to update the impedance based upon engineering judgment that the change is not significant to the impedance model. For emphasis, under R3.2, considering changing “…within 30 calendar days of receiving a request or according to an agreed-upon schedule” to “…within 30 calendar days of receiving a request or according to an agreed-upon schedule, which may be longer or shorter than 30 calendar days.” R4.2 does not seem to explicitly require that a Protection System Study be completed before implementing changes indicated in R3.1, only that the changes are accepted. R1.1.3 seems to suggest that the Protection System Study must be completed prior to implementation. However, according to the flow chart, it appears that a Protection System Study could be produced (in theory) six months after the changes were made. Furthermore, the flow chart applies the six-month timeframe even to R1.1.3, which does not match the text in R1.1.3.
Individual
Jonathan Appelbaum
The United Illuminating Company
Agree

Northeast Power Coordinating Council (NPCC)
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Yes
Yes
No
Request consideration in replacing the time increment of 48 months with 4 years for the time frame.
Yes
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
Yes
Yes
Yes
(1) Austin Energy (AE) notes an inconsistency in R1.1.3 and the flowchart on page 22 of the clean version of Draft #2. R1.1.3 states that a Protection System Study is required “according to an agreed upon time frame” whereas the flowchart on page 22 says “perform the PSS within 6 months.” AE asks the SDT to update the flowchart to match the requirement language. (2) AE believes the VSLs for R4 are not consistent with the language of the standard, specifically R4.1 and R4.2. For example, the Severe VSL language should read “The responsible entity reviewed the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and responded as to whether further action is required, all per R4, Part 4.1, but was late by more than 30 calendar days. OR The responsible entity failed to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to

whether further action is required, all per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of any resulting Protection System(s) changes prior to implementing any planned change(s) associated with Requirement R3, Part 3.1 per R4, Part 4.2." AE is concerned about the current VSL language because it indicates the need to confirm acceptance of planned changes (e.g., new installation) instead of the resulting Protection System(s) changes.
Individual
Jim Howard
Lakeland Electric
Agree
FMPA
Individual
Larry Watt
Lakeland Electric
Agree
Please see FMPA comments.
Group
Dominion
Louis Slade
Yes
Dominion appreciates the SDT's agreement that in PRC 001 there were different interpretations of the term "coordination. Based on the SDT response to our Draft 1 comment regarding "coordination", we now understand that 'coordination' in PRC 027 Title and Purpose is referring to the technical aspects of coordinating relay settings. 2). Please reconsider Dominion previous recommendations to change the Title. "Protection System Interconnected Element Coordination for Performance During Faults" or "Protection System Coordination for Interconnected Elements" have more specificity and meaning to the standards intent for coordinating relays on interconnections.
Yes
Yes
Yes
Dominion interprets the wording "confirming acceptance" to mean that there are no major disagreements and that generally the methods between entities are acceptable using industry protection practices even if different protection setting philosophies' exists. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually

agreed upon response time, can be considered as confirmation of acceptance. The initiating party should not be restricted from applying appropriate settings due to the lack of acceptance confirmation from the other entity.
Yes
1). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. This proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 2). Dominion respectfully disagrees with the SDT feedback comment on Draft 1 where it was recommended to remove references from one Requirement to another Requirement. Dominion was not challenging consistency with the recommendation but were stating the need to simplify the wording in the standard. Each Requirement can stand on its own without the additional Requirement reference. By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement due to the fact that that it causes you to read between Requirements. Isn’t this the purpose of the Process chart in the guidelines? 3). Under R1 – MI measure wording does not read as a completed statement. Dominion suggests removing ‘that’ from the first sentence to “….demonstrating time frames”. 4). Dominion respectfully disagrees with the SDT feedback that in R2 the term “deviation” is synonymous with “change”. Deviation refers to variation from a standard, norm or mean. This is not a statistical calculation but a simple measure of change 5). In R3- 3.2, there appears to be a formatting issue. Any Requirement that references a calendar day is worded where the Calendar date is at the beginning of the statement; for example R3- 3.3. Need to change wording in R3- 3.2 for consistency throughout document to read “Within 30 calendar days of receiving a request or according to an agreed upon schedule, requested information related to coordination….”). 6) In Draft #1 Dominion wrote: “Throughout this Draft 1 of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”. The SDT responded saying “Each measurement in the standard (M1 through M10) has as evidence the statement “dated documentation (hardcopy or electronic file formats).” This is not the case; the point was that M1 reads “either in hardcopy or electronic file formats”. This is minor but needs to be changed for consistency.
Group
SERC Protection and Controls Subcommittee (PCS
David Greene
Yes
Based on the SDT response to our Draft 1 comment regarding the use of ‘coordination’, we understand ‘coordination’ in the Title and Purpose to mean the technical aspect of relay coordination.
Yes

Yes
Yes
1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Yes
Other comments (not associated with Question 5) are being provided which could not be addressed in the questions listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are

confusing. 5). Under R1 – MI measure wording does not read as a completed statement. Suggest removing ‘that’ from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, ‘there is no evidence there is widespread miscoordination of protection systems.’
Group
ACES Standards Collaborators
Ben Engelby
No
(1) We disagree with the inclusion of the “least number of power system Elements” in the purpose. The purpose should be to simply coordinate the Protection Systems for Interconnected Elements. While trying to minimize the number of Elements that should be removed from service is a laudable goal, it will create an incentive for auditors to determine if there is a better way to protect the registered entities systems. How else could an auditor know that the absolute minimum of Elements have been determined unless they tried optimize the zone of protection themselves. The use of different but related terms causes confusion. For instance, what is the difference among “power system Elements,” “Elements,” and “Interconnected Elements”? Based on the definition of “Element,” we assume “power system Elements” is intended to be the same. If so, we suggest dropping “power system” to avoid confusion. (2) Similar to the purpose statement, the Applicability Section, (4.2) Facilities is unclear. The statement “Interconnected Elements of the BES that require coordination for isolating those faulted Elements” includes superfluous language. In general, NERC enforces standards against the BES. Thus, it is not necessary to include “of the BES.” To ensure absolute clarity, we suggest the definition of Interconnected Element be modified to specifically limit it to the BES as well. Also, we recommend striking everything after Interconnected Elements in the purpose statement as it is unnecessary and provides no additional clarification on the Facilities to which the standard applies. (3) Because no generic questions asking for additional comments was provided, we are providing our concerns that do not fall under one of the specific questions asked of the drafting team here. (4) Please change the wording of Part 1.2 as the current wording has some unintended consequences. We think “to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement” should be changed to “to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of the associated Protection System Study.” The current language literally reads that the TO, GO, and DP shall provide the PSS results to itself. It also reads that all the Protection System Studies for a TO, GO, or DP must be provided to the other protection system owners of all of the Interconnected Elements even if the other owners only own protection systems for one of the TO, GO, or DP’s Interconnected Elements. As an example, consider that TO X shares two separate Interconnected Elements with TO Z and GO A.

The Interconnected Element between TO X and TO Z is called Tie-line B and the Interconnected Element between TO X and GO A is GSU C. The requirement would literally require TO X to share its Protection System Study results for both Tie-line B and GSU C with both GO A and TO Z even though, GO A has no interest in Tie-Line B and TO Z has no interest in GSU C. This could be solved with the simple edit described above. (5) We find that addition of "For each Facility associated with an Interconnected Element on its System" in R2 confusing. First, what is an associated Facility? Second what is intended by the use of Facility instead of Element? Considering Interconnected Facility in the last draft was change to Interconnected Element and Facility was used in this requirement, it would appear some delineation is meaning is intended between Element and Facility. Since Element and Facility have nearly the same meaning in the NERC Glossary of Terms that delineation is unclear and we would appreciate further explanation of the intent. (6) We found the inclusion of quotes on the phrase "Protection Systems installed to detect faults on the BES Transmission System" confusing. There is no reference. We suggest removing the quotes as they are superfluous. The meaning is still communicated without them. If they remain, please provide a reference. We assumed it came from section 4.2. If the quote did come from that section, it is not quite correct. It is missing "for the purpose of detecting" and "faults" is not capitalized. (7) The purpose statement of PRC-001-3 needs to be further modified. With the deletion of all of the requirements but Requirement R1, the purpose to "ensure system protection is coordinated among operating entities" is no longer achieved.
No
(1) We recommend modifying the definition of Interconnected Element such that is dependent on actual registered entity ownership rather than functional entities. As an example, a generation Element would only be considered an Interconnection Element if the GO and TO were separate corporate entities. If the functions were the same registered entity, coordination would already occur and the generation Elements should not be considered an Interconnected Element. To do otherwise will only cause significant compliance problems that may not support reliability. A utility that owns generation and transmission may not have a clear point of interconnection. This would be especially true for units installed prior to the advent of open access in the mid-1990s. If the point of interconnection is not well defined, how can an Interconnected Element be defined? It would be arbitrary to pick the GSU or an Element in the switchyard. Furthermore, focusing on ownership would actually make the proposed standard consistent with the existing PRC-001-2. That standard does not explicitly require coordination among different function entities within the same registered entity. (2) Interconnection Element definition is proposing an administrative burden of having to coordinate within the same registered function. Documenting coordination efforts made to external functions is reasonable for reliability; however, keeping records of internal coordination is unnecessary. What would an entity be required to show if there was only one protection system engineer in the organization? Would that single person be required to document coordination among him/her self? We feel that this portion of the definition should be struck – it is more appropriate to clarify the coordination of protection system elements should be among external registered entities in the requirements. There should not be any requirement for internal protection system coordination, especially not in a definition.

No
(1) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates, especially when the requirement is asking for documented studies. After the studies are complete, there is not a need for a timeframe. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (2) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement mirror what is explained in the application guidelines. For instance, we recommend clearly stating in Requirement R1 that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Element. The standard is close to capturing this intent with the statement “its System” in Part 1.1. It would be better it if was changed to “Perform a Protection System Study for each of its Protection Systems that are protecting an Interconnected Element.” A GO and DP do not really have systems so the current language is not appropriate for these functions. The application guidelines provide this clarity and would be helpful if the intent was clearly stated in the requirements.
Yes
(1) We had no issues with the use of agreement in the previous version. Coordination of protection systems is important enough to obtain agreement. Furthermore, we believe confirming acceptance and reaching agreement are synonymous. If two entities need to “resolve differences and confirm acceptance that their Protection Systems are coordinated,” that is the same as stating that the entities need to reach an agreement.
No
(1) The measures do not match the requirements. For example, R4 requires entities to confirm acceptance, which would demonstrate that each affected entity received notification. Again, the drafting team is using synonyms that produce the same result as the prior draft. To show evidence that the information was “provided” would have to be some sort of notification of receipt. (2) Does the drafting team intend further actions for coordination beyond providing the studies to applicable entities? (3) We recommend the drafting team develop an RSAW to better explain how compliance would be measured against this standard. (4) Thank you for the opportunity to comment.
Group
Hydro One Networks Inc.
Sasa Maljukan
Yes
We agree with this Purpose statement and we commend the drafting team for moving this

standard in the right direction. However, in line with our previous comments from the first posting, there still seems to be a significant gap in reliability by not identifying what elements of the Protection System need to be co-ordinated between entities. Perhaps this can even reside in the Application Guide. A poor or incomplete Protection System Study is worthless and negates all the work needed to satisfy this standard. As identified by the drafting team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of say generator loss of excitation protection settings or out of step relaying during a fault condition – is that meant to be covered in this standard or elsewhere? The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions – not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. We feel PRC-027 is an effective vehicle to convey at least the “what” for Protection System co-ordination during faults between entities and will allow entities to perform and document consistent Protection System Studies.
No
For Protection System Study: Suggest adding a phrase:“A study between two or more interconnected power system Elements that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults”.
No
Hydro One believes 60 months is a more appropriate time frame to conduct, document and obtain consensus for a protection system study. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. Large entities and small entities have the same time frame to complete this work which seems unreasonable. Alternatively, an extended period should be provided based on a formula that factors the quantity of interconnected power system elements.
No
This change seems more ambigious than “reach agreement”. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to “confirm acceptance”?
Yes
Individual
Michael Moltane
ITC
Yes
No
The general idea of the Interconnected Element is acceptable. However, when one Registered Entity takes care of coordination between two Functional Entities, or coordinates all protection coordination between the two systems, the documentation will become onerous and not

enhance the reliability of the BES. The definition of the Protection System Study still needs further clarification. It is not clear what calculations/documentation must be kept to properly demonstrate compliance with the requirement of a “study.” Past practice may have kept calculations and correspondence, which adequately demonstrate “evidence of coordination,” but might or might not be adequate to a “protection system study” for future coordination efforts.
No
The amount of work required to comply with this requirement may be significant and may impact ongoing efforts to upgrade and improve the system. The above items that need to be documented can often be discussed and agreed to verbally between parties and are were often not part of a permanent record. The additional record keeping required may be significant and not add to the reliability of the BES.
Yes
Yes
Figures 1-5 designate a preferred responsibility of coordination on either entity which contradicts with intent of R3. R3 details all the changes which must be provided to the adjacent utility, seemingly so they can coordinate their protection over yours. However, Figures 1-5 place the coordination responsibility on the utility which does not own the Protection System. I agree that R3 should remain almost as-is. However, the coordination responsibilities in Figures 1-5 should be reversed or preferably removed. Owner R should be responsible for coordinating Breaker A relays. Only the owner should be responsible for coordinating this relay. SDT needs to define the term “interconnecting bus” and perhaps identify the interconnecting bus in Figures 1-5. In Figures 1-4 the Interconnected Element is a line.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the purpose statement, but suggest to add “settings” after protection system (with the “s” removed”) to make it clear that it is the coordination of the settings, not the design of protection systems.
No
The definition of Interconnected Element is confusion since there is a mixture of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest to replace Functional Entities with asset owners or facility owners. If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses
Yes
Yes

We agree with the intent of the proposed changes, but believe some editorial changes are necessary for more clarity. We suggest the following wording for the SDT's consideration: "Confirm with the owner(s) of each Facility associated with the affected Interconnected Element that it accepts (or acceptance of) the resulting Protection System(s) changes." In fact, Part 4.1 could also be worded to add clarity: "Within 90 calendar days after receipt of the proposed Protection System(s) changes,"
No
(1) We do not have a strong view one way or the other with respect to "provided" versus "demonstrating". However, the wording used among Measures needs to be consistent. For example, in M1 the wording is "Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of…" seems reasonable since it shows the examples for "acceptable evidence". The examples listed illustrate what constitute "acceptable evidence". However, in M2, the wording "Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided…." Does not illustrate what constitutes "acceptable evidence", thereby leaving that to interpretation. We suggest M2 (and M4) be reworded along the same line as that for the other Measures (M1, M3, M5 to M9). (2) The Comment Form does not have a question on "Do you have any other comments?" Therefore, we are submitting the following comment under this Question. We reiterate our concerns previously expressed with respect to PRC-001: We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the "Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. The SDT's response to our previous comment was "This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff." We do not believe that the staff has brought this to the Standards Committee's attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel.

Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1.1 a. ReliabilityFirst questions the rationale for the 48 calendar month window to perform a Protection System Study if NO study exists. ReliabilityFirst believes that a Protection System Study is one of the fundamental reasons for the standard and believes if NO study had ever been performed, one should be performed as soon as possible (12 months). Within the rationale section, the SDT states: “The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.” With no widespread mis-coordination of protection systems, ReliabilityFirst questions the actual need for the standard itself. 2. It is not clear where the 10% threshold in Part 1.1.2 and calculated in Part 2.1.2 is applied. Does the 10% threshold apply to the total bus Fault current at the interconnecting bus or the contributing Elements? If it is the total, then there are situations where some of the sources into the bus may change their contribution quite a bit more than the 10% threshold but yet the total change could be less than 10%. Protective relaying is set in reference to the Element it is protecting or, to be more precise, the instrument transformers associated with an Element. The 10% threshold should be applied to the Interconnecting Element as its contributing quantities could change significantly even if the total Fault current stayed nearly the same. It is the Fault quantities on the Element that the interconnection protection sees – not the total bus Fault current (unless the Interconnecting Element is a bus). It is also not clear which phase or sequence currents are being used in the %Deviation calculation. Is it 3I0 (3 times zero sequence) current for single line to ground Faults and I1 (positive sequence) current for 3-phase Faults? It should be noted that if variations in Fault current of 10% are acceptable, then entities may need to adjust their criteria to use margins of 15% or more to consider other sources of error such as relay and instrument transformer accuracy.
Yes
ReliabilityFirst abstains and offers the following comments for consideration: 2. Requirement R4 Violation Severity Level a. During the previous comment period, ReliabilityFirst recommended that VRF for R4 be changed to “High” since this is dealing with interconnection protection systems. The SDT response by indicating they “…believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk. “ After reading the NERC criteria for a medium risk, ReliabilityFirst would agree only if the Time Horizon of this requirement is

changed to “Long Term Planning”
ReliabilityFirst offers the following comments on the VSLs for consideration: 1. Requirement R3 VSL a. ReliabilityFirst believes VSL for Requirement R3 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” Requirement R3, Part 3.1 and 3.1 requires the entity to provide “details” and the associated VSLs references “information”. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement. b. It is unclear which requirement the last VSL under the “Severe” category is referring to. ReliabilityFirst recommends adding the Part number in which the VSL is associated with. 2. Requirement R4 VSL a. ReliabilityFirst believes VSL for Requirement R4, Part 4.1 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” The VSLs associated with Part 4.1 use the language “confirmed acceptance” though the language in the actual Part talks about review of summary results and response as to whether further action is required. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement as follows: “The responsible entity reviewed the summary results of a Protection System Study and responded as to whether further action is required per R4, Part 4.1, but was late by 10 calendar days or less”
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
Yes
Yes
Yes
R1 The requirement is written to be applicable to Transmission Owners. In our case we have several lines where we do not own the Interconnecting Element, but operate the Protection System at one terminal. Based on the Glossary, we believe this makes us a Transmission Operator. If this interpretation is accurate, there would seem to be a gap in the Applicability of the Standard, as it does not include the Operator. R2 We are wondering why this Requirement is only applicable to the Transmission Owner. Should it not be applicable to all the functional entities similar to the language used in R1, R3, and R4? General comments In reviewing the Standard, there was confusion related to the Protection System Study and what the 10% was measured against. We believe that the Protection System Study referred to in the Standard is that group of faults and contingencies used to create the in-service settings of the relay. Could this be clarified? Additionally, the exchange of information between Functional Entities is a

critical part of PRC-027, however, no mechanism is in place to ensure proper contact information is available. Employee movement within a utility may render contact information obsolete. In addition, Independent Power Producers, such as wind farms, are not typically staffed by local personnel or by individuals with a knowledge of System Protection. Because PRC-027 relies so heavily on the exchange of information it is not sufficient to simply place time lines on the transfer of data between Functional Entities. Additional controls to ensure that these data requests reach the appropriate people is needed.
Individual
Brian Murphy
NextEra Energy
No
See page 19 of the redline PRC-027 Guidelines and Technical Basis. “ System condition used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions.” Please clarify that “single contingency conditions” refers to breaker failure or protective system failure. It is not intended to mean single contingency operating conditions such as line or transformers out of service.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
No
Clarification is necessary for the definition of “Interconnected Element” which requires the TO and GO function within a company to treat each other as if they were unrelated entities and apply all of this standard’s requirements.
No
“The results based objective is that the registered entities communicate and coordinate with each other. A simple statement by both entities that they have reviewed each other’s settings and agree they coordinate is sufficient proof that the reliability objective of this standard is met.” Performance of a PSS is an intermediate step toward achieving coordination. It does not improve reliability if an entity does not act on it. Only in the final step – when agreed upon changes are made – does system reliability actually improve. The standard should consist of R3.1 (one side makes a change which triggers a review), followed by R4.2 (all parties agree to

the changes to be implemented). Documenting the process steps between these two points in time does not improve system reliability.
Yes
Yes
Although this is unrelated to Question 5 there was no other space allocated for the for "any other comments." While this is most likely a clerical error, we feel it is not appropriate to post a standard without making such a question available.
Individual
Saul Rojas
New York Power Authority
Agree
NPCC
Group
seattle city light
paul haase
Yes
No
Seattle City Light does not agree with the use of Functional Entity in the definition of Interconnected Element. Seattle has several objections. First, although "Functional Entity" is capitalized in the draft Standard, this term is not defined in the NERC Glossary of Terms. A second objection is that "Functional Entity" in this role does not add clarity to the Standard. "Functional Entity" is defined in the NERC Reliability Functional Model as "the term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function." This definition refers to other terms defined only with the Functional Model document ("Task," "Function"). It is not illuminating as to defining the bodies joined by Elements. The third and strongest objection is that use of the term "Functional Entity" in the proposed definition is incorrect and inconsistent with the NERC Functional Model, and as such creates confusion about Standard obligations for entities registered for more than one function. The NERC Functional Mode Version 5 (November 30, 2009) explicitly does not require any particular organization or assignment of functional Tasks or ownership of Elements for any multi-function entity. Functional tasks and Elements exist undifferentiated across an entity as a whole, and the NERC Functional Model document states clearly that no further differentiation is expected, required, or implied. (See, for example, p. 7 "The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term 'functional entity', is a guideline and cannot prescribe responsibility" and p.8 "The Model is independent of any particular organization or market structure.") Seattle City Light, for example, is a vertically integrated municipal utility registered for 11 functions: BA, DP, GO, GOP, LSE, PC, PSE, RP, TO, TOP, and TP. Registration is

made without differentiation: no particular sub-organization within Seattle City Light is identified as owning GO Elements, TO Elements, and so on. The Model is simply that Seattle City Light or any other multi-function entity owns a set of Elements s a unit. By contrast the draft definition relies upon differentiation of ownership of Elements within a multi-function entity, so that it can be determined if the proper studies were undertaken or not. Such differentiation is outside the Model and introduces complexities and unintended consequences not envisioned by the Functional Model and the term “Functional Entity.” The same confusion about the term Functional Entity occurs in draft Standard COM-003-1. Seattle suggests that NERC immediately clarify the use of this term. Until the definition of the Functional Model is changed and changed significantly, the use of Functional Entity to define obligations within a Standard or definition (other than in the Applicability section) should be eliminated. As is it is simply a misreading, tempting as it may be, to presume that Functional Entity Tasks are assigned with greater granularity than to an organization as a whole. And it is a misreading that does not promote high quality Standards that can be consistenly enforced across auditors and across regions. You can do better, and should do better. Seattle apologies that it does not have a suggested fix at this time, because the Functional Entity approach is so fundamentally wrong. Entitly new wording would be required to capture Elements existing within the same registerd Entity.
Yes
Yes
No
Because there is no "other comments" section included in this comment form, the following comments about the timelines for specific actions are appended here. (R3.2) "Data Requests . . . . 30 Days or agreed to schedule' Seattle requests that "agreed to schedule" be clarified, in particular the limits in determing this schedule. If no further clarity is added, Seattle suggests that "or agreed to schedule" simply be deleted. (R2.1) Short Circuit Study . . . . . . 24 months SCL recommends that the time line of 24 months be removed and that the 10% change in fault current criteria serve as the replacement for this requirement. (R4.1) "Review PS Study . . . . .90 Days or agreed upon schedule" Seattle is concerned that, depending upon the complexity of the study, a lot of back and forth communication between the utility entities may be required. Please clarify 1) if each response to, or revision of the study trigger another 90 day review period and 2) the limits as the defining an "agreed to schedule." If no further clarity is added regarding agreed to schedules, Seattle suggests that "or agreed to schedule" simply be deleted.
Individual
Stephanie Monzon
PJM Interconnection

PJM supports revising the language in Requirement 1 of PRC-001 by replacing the term ‘familiar.’ This word is ambiguous and confusing in terms of the specific expectations of the applicable functional entities regarding the purpose and limitations of protection system schemes applied in its area.
Individual
Eric Salsbury
Consumers Energy
The following comments are unrelated to Question 5. However, there has not been a question/section added for other/general comments. 1) In the process flow chart (page 22) the R2.2 box which states “Within 30 days, provide each owner of the Protection System associated with the Interconnected Element”, we believe the key element, “the updated Fault current values” was not included in this statement. 2) In reading the Example Process on page 23, we were expecting to be able to follow it through the process flow chart on page 22 as one possible example to guide you through the standard process. As it started off as a request for information, we assumed the flow process started in the R3 box “Data request” which indicates no further action. Yet the example process continues on. We would suggest an improved explanation paragraph be added to the “Example Process” to better clarify what the example is intended to illustrate.
Group
pacificorp
ryan millard
Yes
Yes
Yes
Yes
Yes

Individual
Richard Vine
California Independent System Operator
Agree
The California ISO is in support of, and has signed on with, the comments submitted by the Standards Review Committee (SRC) (ISO/RTO Council).
Group
FirstEnergy
Larry Raczkowski
No
In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
No
FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not “separate Functional Entities” but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element “An Element that electrically joins and interconnects facilities owned by: a) separate Registered Entities, or b) the same Registered Entity, but includes multiple functional entity (DP, GO or TO) responsibilities.”
No
A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the SDT may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. B) As expressed in FirstEnergy’s Draft 1 comments,

we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. C) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text ** R1. Each Transmission Owner shall perform a Protection System Study for each Iterconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] • the protective relay settings reviewed • power system Elements to be isolated • contingencies evaluated • Fault currents used • any issues identified • any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement. **End of proposed requirement R1 text ** FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.
No
FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially trigger upgraded Protection System Studies being communicated without "acceptance" prior to their implementation.
Yes
FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter

that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks like the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity". E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Group
Florida Municipal Power Agency
Frank Gaffney
No
The primary purpose of protection system coordination is to ensure faults are cleared expeditiously and well under the critical clearing time, with the stated purpose of minimizing the number of elements isolated as a secondary consideration, not a primary consideration. As such, there is no recognition of the importance of remote back-up protection that backs up primary and secondary protection, but, does not necessarily share the same goal of minimizing number of elements tripped, but, does share the goal of clearing a fault within the critical clearing time.
No
The definition of Interconnected Element limits the scope of the standard too much. The standard only requires coordination between neighboring entities and not of protection of other BES equipment within the same entity, e.g., one TO’s transmission line protection with the protection of another transmission line owned by that same TO is not within the definition of Interconnected Element. It would seem that such a requirement would be necessary, e.g., each entity ensures that their protection internal to their system coordinates with itself, and that they coordinate at the boundaries with its neighbors. That would ensure coordination across the BES. Protection System Study definition should have a time element and a consideration for the critical clearing time, e.g., “and demonstrates that the resulting clearing time meets or beats the clearing time used in studies to comply with the TPL standards” or something to that effect

No
As worded, R1 seems to require two neighboring entities to perform independent studies. We would hope that the intent of the SDT is to allow any one entity to do a study and then the neighboring entity accept the results of that study, or to perform a joint study. We suggest the SDT make conforming changes to allow this.
Yes
No
First, there should be an “any other comments” question. Seeing that there isn’t one, we are adding our other comments here. R3 – There should be thresholds of change to the bullets. For instance, changing the no-load tap changer of a GSU does minimally change the impedance of the GSU). A transmission line neighbor installing a long chain link fence along the ROW will have a minimal impact on mutual coupling. These minimal changes do not require redoing the study, so, what percentage change in impedance requires redoing the study?
Individual
John Bee
Exelon Corporation and its affiliates
No
Exelon agrees with the Purpose statement as stated, however the questions and layout of this comment form doesn't provide an area to provide comments as to why we are voting negative. While requiring periodic coordination studies between entities is laudable, it is unnecessary. The coordination of a protection system, by nature, is tested every time it operates. We already have a standard, PRC-004-2, that requires all transmission protection system operations to be analyzed for correctness and any misoperations reported, along with corrective action plans to mitigate their cause. Our experience indicates the bulk of protection system misoperations are not caused by a lack of coordination studies. This standard, as written, continues to be vague and will lead to an inconsistent application of the requirements. Most importantly, we believe this standard is ill advised. Coordination of protection systems between entities was not a factor in the 2003 blackout. As such it clearly goes beyond the mandate of the 2003 blackout recommendations. Implementation of this standard will add little to the reliability of the bulk electric system while adding substantially to the amount of time and money an entity spends simply on compliance activities. Contrary to the goal of enhancing reliability, this standard will simply dilute available resources to the detriment of reliability.
Yes
Yes
Yes

Individual
Don Schmit
Nebraska Public Power District
No
It seems the real purpose of this standard is “To coordinate BES Protection Systems for Interconnected Elements”. The rest of the statement is already covered as part of the protection systems design which will involve coordination or not depending on any special issues or existing design limits.
Yes
No
To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6 years based on two audit periods (time depends on the number of applicable system ties as well).
No
Getting acceptance within the required time frame is not in the control of the requestor. The concern is the numerous timelines in this standard that require timely responses will create an overly complex standard that will be difficult implement and to audit. The starting points for the timelines will be difficult to audit as well since much of this must be determined between two or more entities. How will enforcement view a requesting utility that sends a timely request but the response is a late confirmation of acceptance? The numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking dated communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 90 days, 6 months, 2 years and 4 years”. There should be fewer and simpler time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole: “The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable “prior to the in-service date,” At a minimum remove the calendar day references and make them all 6 months for simplicity so the option is to use and agreed upon time or 6 months. Possible Suggestions: A simpler method would be after the initial 4 years to perform a study then every

24 months perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the interconnecting bus per Requirement R1 and demonstrate that the fault model was provided to the interconnecting entities within this time period along with the settings so the receiving entity can review against their design. Auditing would verify this data was sent on a two year schedule. For new protection interfaces verify protection studies or relay settings or summaries of studies were exchanged for review prior to the equipment going in service.
No
Measurement 9 for R4 requires confirmation of acceptance prior to implementation of any planned protection system changes. This appears to be similar to ‘demonstrating that each affected entity received notification.’ The concern is holding one company responsible for actions of another that is not under the requestor’s control. It is recommended that there be clarification that if the requestor does not get confirmation of acceptance in the proper time line then the requestor is not accountable or subject to violations. Another option is to remove R4.2.
Group
Certain Members of the ISO RTO Council
Charles Yeung
No
Although the SRC agrees that protection systems should strive to interrupt only those elements closest in to a fault to avoid excessive interruptions, there are situations where it is necessary to trip elements beyond those that only interrupt the fault. To set a result for “…the least number of power system Elements are isolated to clear Faults” misses the primary goal for a reliability standard meant to protect the interconnected bulk electric grid. NERC standards should always have the underlying purpose to prevent cascading failures that affect interconnected systems. The stated Purpose must recognize that the “least number of power system Elements are isolated to clear Faults to maintain system integrity”. For example, a relay scheme could isolate a fault on a generator connected between two line terminals by opening the breakers on both ends of the line. This would fulfill the Purpose of “least number of power system Elements”, however, a protections scheme for that segment of transmission line may require that the next terminal along that line also be interrupted in order to prevent an unintended increase in load to a particular element due to the opening of the breakers closest to the fault.
No
The definition of Interconnected Element is confusing since there are a mix of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest replacing “Functional Entities” with “asset owners” or “facility owners.” If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses The SRC asks if the definition for “Interconnected Facility” needs to be expanded to include situations where a Functional Entity may cross regional boundaries and have facilities that interconnect

between the two, which may or may not be the same Registered Entity.
Yes
Yes
Yes
NERC must continue to correct such requirements, as it is not the responsibility of the entity subject to a requirement to ensure another party acts.
Group
FirstEnergy
Doug Hohlbaugh
No
In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
No
FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not "separate Functional Entities" but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element: "Interconnected Element - An Element that electrically joins and interconnects facilities owned by a)separate Registered Entities, or b) the same Registered Entity, but includes those representing multiple functional entity (DP, GO or TO) responsibilities."
No
A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the SDT may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems

operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. B) As expressed in FirstEnergy's Draft 1 comments, we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. C) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text ** R1. Each Transmission Owner shall perform a Protection System Study for each Iterconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] - the protective relay settings reviewed - power system Elements to be isolated - contingencies evaluated - Fault currents used - any issues identified - any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement. **End of proposed requirement R1 text ** FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.
No
FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially trigger upgraded Protection System Studies being communicated without "acceptance" prior to their implementation.
Yes
FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation

Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks like the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity". E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
No
The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-

scale wind farms) need to be included in PRC-027 the standard should address that specifically. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Fnctional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO’s system.
No
The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
Yes
Individual
Marie Knox
MISO
Agree
MISO supports the comments submitted by the Standards Review Committee (SRC).
Individual
Jim Cyrulewski
JDRJC Associates
Agree
Midwest ISO
Group
Tennessee Valley Authority
Dennis Chastain
Yes

Yes
No
We do not feel like 48 months is a reasonable timeframe to meet the minimum requirements for Protection System Studies (PSS). In the current form of the standard, for an existing PSS to be valid, several minimum requirements are given in R1.2. While this is a good requirement for new PSS, it eliminates almost all of our existing PSS as being valid. We have the stance that many of our existing PSS are of a high quality and should be considered valid, but do not meet the minimum requirements from R1.2. We recommend allowing existing PSS to be submitted in their current form between all protection system owners of an Interconnected Element within a reasonable time frame of the standard effective date and allowing the owners to approve the existing PSS as valid if they desire. Then, that existing PSS could be used as the baseline PSS until the 10% change in fault occurs from the existing dated PSS. At that time, a new PSS should be performed to meet the minimum requirements as outlined in R1.2.
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
The purpose of this study should be “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the proper sequence.” The least number of Elements to clear a Fault may not always be the case for some Protection Systems. The TO and TOP are provided with detailed information of the GO’s equipment and therefore perform all interconnection-related studies. Independent generators do not modify Protection Systems in response to changes to the Fault current at an interconnecting bus, generators just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Equipment involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e., reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should specifically address those GOs, rather than pulling in all GOs. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
No
As per this version, the standard’s protection study requirement seems excessive. The

definition of a Protection System Study needs to include identification of the party responsible for performing this work, which should be the TO for the reasons discussed above.
No
Sixty months would be more appropriate to study all the interconnections. There has not been a major problem with mis-coordination of Protection Systems associated with Interconnected Elements. Also, the standard does not fully address what all should be included in a Protection System Study. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Yes
There is no clear responsibility in the standard if both parties cannot confirm acceptance.
Yes
Individual
Clay Young
SCE&G
No
SCE&G disagrees with the definition of “Interconnected Element”. More clarity is needed regarding the language “Functional Entities that are part of the same Registered Entity”. Entities that are vertically integrated and more specifically those vertically integrated companies that that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves.
Individual
Daniela Hammons
CenterPoint Energy
No
CenterPoint Energy believes the purpose should use wording similar to that being proposed for the definition of “Protection System Study” instead of developing and utilizing different wording for the purpose statement. CenterPoint Energy recommends the purpose be stated as follows: “To coordinate Protection Systems for Interconnected Elements, such that Protection Systems operate as desired for clearing postulated short circuit Fault events.”
No

CenterPoint Energy recommends the term “Protection System Study “ be defined as follows: “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing postulated short circuit Fault events.”
No
(a) CenterPoint Energy continues to believe a requirement to have a documented Protection System Study for each existing Interconnected Facility is overly burdensome, unless certain – if not all – existing Interconnected Facilities are exempted; therefore, CenterPoint Energy recommends R1.1.1 be eliminated from PRC-027-1. CenterPoint Energy does not believe a reliability need has been identified to justify that such prescriptive requirements are needed to provide for an adequate level of reliability. The following is stated on page 18 of 28 in PRC-027-1 Draft 2: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” The majority of existing Interconnected Facilities have fault-proven, time-proven protection system set points. An existing Interconnected Facility without a documented Protection System Study will eventually be included in a study with system additions and changes, short circuit current increases, and relay panel replacement projects, as well as any analysis of misoperations. (b) While an option has been included in Draft 2 R1.1.3 to allow for a technical justification why a study is not required for certain changes, CenterPoint Energy believes that reasonable thresholds should be established for the changes identified in R3.1. For example, R3.1 requires that “any” change of sequence or mutual coupling impedance must be provided to a Generator Owner. For insignificant changes of sequence or mutual coupling impedance, CenterPoint Energy believes there would be little, if any, reliability benefit of communicating and technically justifying why a study is not required.
No
Providing schedule information and project details by a transmission service provider to a generation entity may be governed by established, regional market rules that provide for what information can be shared with competitive entities. There are many installations in the ERCOT System where the owner of the interconnecting switchyard is not the same entity as the owner of the interconnected generation facility.
Individual
Greg Davis
Georgia Transmission Corporation
Yes
Based on the SDT response to our Draft 1 comment regarding the use of ‘coordination’, we understand ‘coordination’ in the Title and Purpose to mean the technical aspect of relay coordination.
Yes
No

Guidelines and Technical Basis Req. R1: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."... ...These studies may include graphical coordination....; relay scheme simulation studies....; and sensitivity studies using sequence...., and adequate directional polarizing quantities. This activity will be onerous without a full system model and software to perform studies that would check coordination of stacked curves and stepped distance relays. Of particular note is the question of adequate directional polarizing quantities. There should be an expected minimum requirement such as time overcurrent plots and zone distance plots of the existing relay settings for the terminal with the fault points used as the basis. This data would then be used to indicate if the 10% point has been reached that would require a new coordination follow up at the end of the next 24 month fault study.
No
1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Yes
Other comments are being provided which could not be addressed in question 1 - 5 listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels,

respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 – MI measure wording does not read as a completed statement. Suggest removing 'that' from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'
Individual
Scott McGough
Georgia System Operations Corporaton
Agree
Georgia Transmission Corporation
Group
Duke Energy
Greg Rowland
Yes
The Purpose statement could be improved by striking the phrase "least number of power system Elements are isolated to clear Faults", and inserting the following phrase from the definition of Protection System Study: "Protection Systems operate in the desired sequence for clearing Faults". Some entities may choose to "over-trip" for certain Faults.
Yes
The SDT should consider putting the definition of Interconnected Element in the NERC Glossary.
Yes
Yes
Yes
Additional comment: R2.1.1 refers to "maximum available Fault current values", but it's unclear from the requirement or the Guidelines and Technical Basis how "maximum" is defined. We believe it should be maximum generation and all Facilities in service.

Group
JEA
Thomas McElhinney
No
Seems like Interconnect element is too broad and not enough clarity on what a protective system study requires (Ie, is this a setting coordination study? Redundancy studies? Dynamic studies? Duplication of TPL requirements.
Yes
There is no place to put in a comment for R2 so this is for R2. We believe that the requirement to perform an analysis should be changed from once every 24 months to once every 36 months. Whenever changes are done to the system an analysis is done so this for areas that have not changed and we believe that once every 3 years should be sufficient.
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
No
The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. The purpose in the draft standard makes it appear that you are in violation of this standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used, but the measures tend to measure agreement with the other entity. PRC-004 is the standard for misoperation reporting and misoperation mitigation.
No
At our company there is one engineering group doing Protection System Studies for all Functional Entities and for multiple Registered Entities. Reliability is not enhanced by requiring a single engineering group to document and be audited for coordination with itself. An Interconnected Element should be defined as an element that electrically joins facilities that are controlled by separate operating companies and Protection Studies are done by separate engineering groups.

No
Proposed Requirement R1 allows 48 months to do an initial study with the explanation that there is no evidence of widespread miscoordination. We agree that there is no evidence of widespread miscoordination and therefore 60 months is the proper time frame for an initial study. We have also noticed that there is no question on this comment form for any other comments not addressed by the drafting teams questions. As such we note here that Requirement R1, 1.1.2 lists a 10% change in current as an action point. This implies that a 10% decrease requires action. We do not agree with this since most Protection Studies are done with all generation on. Most of the year all generation is not on with the result that normal operating conditions result in fault currents that are 10% below the maximum used in the Protection System Study. We also disagree with action required for a 10% increase in fault current since our standard relay settings no longer trip for instantaneous ground over current elements and the standard does not allow an entity to state a reason not to run this study or perform the calculations. When we did utilize instantaneous ground over current elements we allowed a 40% margin. We utilize other high speed protection elements not directly affected by changes in fault current. We recommend at least a 20% change in fault current to require action per this standard. Requirement R2 requires that a short circuit study be done every 24 months. As noted above 60 months is proper time for initial study and is also proper for subsequent studies done after the initial study is complete.
Yes
Yes
Group
Western Electricity Coordinating Council
Steve Rueckert
We agree that unnecessary power system Elements should not be isolated to clear Faults, but question the statement that the “least number of power system Elements should be isolated.” Reliability should be the goal. There may be situation where different isolation schemes both work, but perhaps one that isolates one or two more elements is more reliable.
Yes
We agree with the definitions, but question the appropriateness of development of terms for a specific standard. Individual Regions are strongly discouraged from defining terms that only apply in a single region. We see the development of a term that is only applicable to a single standard to be a similar situation, leading to a proliferation of terms. If this approach is acceptable to NERC and FERC, we have no concerns.
No
Creating a Protection System consists of conducting Protection System studies and incorporating the data into an entity’s transmission/generation/distribution system. Protection System studies are not a new concept to entities. In the event that an entity discovers that

certain interconnected elements are not included in the Protection System study the entity should not require 48 months to make the needed changes to the study. From a reliability perspective, entities should already have a basic Protection System study in order to have a Protection System. Allowing an additional 48 months creates a potentially large 4 year reliability gap based on entities existing studies and any needed corrections. From a compliance perspective, allowing a 48 month time frame for entities to have a documented Protection System study effectively pushes mandatory compliance for this standard out for an additional four years beyond the effective date. This time frame is excessive and should be reduced to no more than 24 months from the effective date of the standard.
Yes
Yes
Individual
Angela P Gaines
Portland General Electric Co
No
Portland General Electric Company appreciates the drafting team's consideration of comments. Since there wasn't a general comment section at the end of this form, the discussion of timeframes seems appropriate here. The effective date (the first quarter six months after approval) does not allow sufficient time for compliance. This standard will require that entities include in all interconnection agreements a detailed protection coordination schedule or be subject to the long timelines detailed in the standard. None of the agreements (if they even exist) for projects six months out include a protection coordination schedule, nor do their project schedules accommodate the long durations detailed in the standard. Agreements will also need to be drawn up for smaller projects in order to document a protection coordination schedule, lest the interconnecting utility prevents us from energizing by taking the full 90 days to review the relay settings. In addition, entities may need at least one additional resource to conduct the bi-annual coordination studies and manage the interconnection due dates. PGE suggests an implementation period of 24 months since planning is done more than a year in advance.
Individual
Alice Ireland
Xcel Energy

Yes
Yes
Yes
No
Requirement 4.2 requires entities to receive evidence confirming acceptance of changes prior to implementing these changes. This coordination already occurs, and we believe this should be a standard practice for all applicable entities. However, we do not agree that this documentation-only requirement is necessary or beneficial to reliability. Instead, we believe this would deter valuable resources to unnecessary compliance evidence activities. Therefore, we recommend that this requirement be eliminated.
No
Since the SDT did not provide a question for “any other comments”, Xcel is using this question for that purpose. 1) We would appreciate some additional clarity as to what transmission fault conditions need to be evaluated by the Generator Owner. Figure 2 does not apply to very many of our units (on most, Breaker A would not exist and Breaker C is part of a breaker-and-a-half scheme). Is the generator supposed to evaluate only faults on the line between the GSU Transformer and the substation or evaluate his protection settings for a fault on any of the transmission lines leaving the substation? Can the drafting team, either as part of the Application Guideline or in a separate document provide a list of protective functions the Generator Owner needs to evaluate or is it the complete suite of protective functions defined in the NERC SPCS Generator – Transmission Protection Coordination Guideline? 2) Requirement 3.1 is onerous as it requires notification for an open ended “when the proposed change modifies the conditions used in the coordination of Protection Systems.” The requirement should be limited and instead provide a simple list of element changes that generally affect coordination with adjacent Elements. 3) Similarly for 3.3, we recommend that this be modified to limit the scope to only changes that result in a change of performance or ratings. For example, settings that change the alarm conditions for a device or a “like-for-like” replacement should not be required to be communicated. Communicating every change would not improve reliability and would instead deter valuable resources to unnecessary compliance evidence activities.
Individual
Karen Webb
City of Tallahassee
Yes
Yes

No
These phrases do not appear to be contained within draft two.
Yes
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Rich Salgo
NV Energy
No
Concerned that the Applicability and Purpose are encroaching upon Distribution elements, outside the statutory authority of the NERC Standards process
Yes
Yes
Group
Southern Company
Antonio Grayson
Yes
Yes
No
For large entities with hundreds of generators, a longer initial time frame is needed. In addition, consideration should be given to the fact that existing transmission protection and control engineering personnel will be fully engaged in the work associated with FERC order 754 for The next 12+ months.
No
The parties at the opposite ends of an interconnecting facility may not have the same

protection philosophies, and acceptance may not be achievable. It is unclear what it means to confirm acceptance. Does this mean that the two must come to an agreement for each other's protection system settings, or is it acceptable to agree that we disagree?
Yes
We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO,GO, and DP. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo), studies triggered by change of equipment or change of fault current (6mo), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days) , short circuit studies (24 mo), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements. R1). Require the two parties of the Interconnecting Element to jointly develop a Protection System Study- initially with X months to complete. R2). Require a review/update of the protection system study for proper coordination anytime a change to the system may upset coordination. R3). Require a review/update of the protection system study for proper coordination every X years. The corresponding measures for each proposed requirement could be... M1: has a protection system study been performed by the initial required date? M2: has a protection system study been reviewed/updated for system changes which impact the coordination? M3: has the protection system study been reviewed/updated every X years? During an audit period these requirements and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will result in an equally effective driver to establish coordination while keeping the standard as succinct as possible.

Additional Comments:

ATCO Electric (AE) – Requirement R1.1.2 – A 10% change in fault current isn’t much in some areas of AE’s system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings

Southern Company – In general, for protection on the transmission line leaving the plant, the generator owner should be responsible only for coordinating with the first set of line relaying encountered when proceding across the interconnecting element. He should not be responsible for coordinating with relaying at the opposite end of the interconnecting element. For example, in Figure 5 on Page 28 of the draft standard, Generator Owner T should not have to worry about a review of the relaying located at breakers G, F, or E. Another example is Figure 2, Page 25 of the draft standard: Generator Owner R should not be responsible for reviewing the relaying at the breaker C.

We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO, DP, and GO. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo.), studies triggered by change of equipment or change of fault current (6 mo.), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days), short circuit studies (24 mo.), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements.

R1) Require the two parties of the Interconnecting Element to jointly develop a Protection System Study - initially with X months to complete.

R2) Require a review / update of the protection system study for proper coordination anytime a change to the system may upset the coordination.

R3) Require a review / update of the protection system study for proper coordination every X years.

The measures for each requirement should simply be M1: has a protection system study been performed by the initial required date?; M2: has a protection system study been reviewed / updated for system changes which impact the coordination?; M3: has the protection system study been reviewed / updated every X years? During an audit period, these requirement and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will results in an equally effective driver to establish coordination while keeping the standard as succinct as possible.