Meeting Notes

Project 2010-05.1 – Protection Systems (Misoperations) Standard Drafting Team

March 18-21, 2014

NERC
Atlanta, GA

Administrative

1. Introductions and chair remarks

The meeting was brought to order by Mark Kuras, chair, at 8:02 a.m. Eastern Tuesday, March 18, 2014. He thanked everyone for joining and noted that it was disappointing the standard only received 62.63% industry approval given his and the team's outreach. Mr. Mark Lauby, NERC Vice President of Standards Development, provided opening remarks about the team's efforts. He understood the team has been working on the standard for over two years and encouraged the team to march ahead noting that he leaves resolving the issues in the hands of the subject matter experts. Mr. Kuras brought attention to the team's recent work with conducting outreach leading to higher approval. This is a change from the past mode of trying to gain industry approval only through postings and webinars. Mr. Barfield took a roll of members and observers. Those in attendance were:

Name	Company	Member / Observer	In-person (IP) / Web (W)			
			3/18	3/19	3/20	3/21
Mark Kuras, P.E.	PJM Interconnection, Inc.	Chair	IP	IP	IP	IP
Martin Bauer, P.E.	U.S. Bureau of Reclamation	Member	IP	IP	IP	IP
Mark Gutzmann, P.E.	Xcel Energy, Inc.	Member	W	W	W	W
Bill Middaugh, P.E.	Tri-State Transmission & Generation Association, Inc.	Member	IP	IP	IP	IP

Name	Company	Member / Observer	In-person (IP) / Web (W)			
			3/18	3/19	3/20	3/21
John Miller, P.E.	Georgia Transmission Corporation	Member	IP	IP	IP	IP
Steve Paglow, P.E.	American Electric Power	Member	IP	IP	IP	IP
Rick Purdy, P.E.	Dominion	Member	IP	IP	IP	IP
Patrick Sorrells, P.E.	Sacramento Municipal Utility District	Member	IP	IP	IP	-
Tom Bradish	Federal Energy Regulatory Commission	Observer	W	W	W	W
Scott Barfield-McGinnis, P.E. (Standard Developer)	North American Electric Reliability Corporation (NERC)	Observer	IP	IP	IP	IP
William Edwards (Counsel)	North American Electric Reliability Corporation	Observer	IP	IP	IP	-
Michael Gildea (Reliability Standards Advisor)	North American Electric Reliability Corporation	Observer	W	W	W	-
Al McMeekin, P.E. (Standard Developer)	North American Electric Reliability Corporation	Observer	-	IP	-	-
Phil Tatro, P.E. (Technical Advisor)	North American Electric Reliability Corporation	Observer	IP	IP	IP	IP
John Seelke	Public Service Enterprise Group	Observer	W[1]	-	-	-
Phil Winston	Southern Company	Observer	-	IP[2]	-	-

[1] Participated only in discussing PSEG comments directly with the team members.
[2] Attended briefly to discuss the GO, GOP, TO, and TOP relationship to the standard.

2. **Determination of quorum**

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

3. **NERC Antitrust Compliance Guidelines and Public Announcements**

   NERC Antitrust Compliance Guidelines and public disclaimer were reviewed by Mr. Barfield. There were no questions. Mr. Barfield also referred everyone to the two NERC policies and encouraged anyone that was unfamiliar with the policies to locate them on the NERC website for further review. The policies are related to use of the email listserv and standard drafting team meeting conduct. Mr. Barfield reminded the meeting participants at the start of each subsequent day that they were under the NERC Antitrust Compliance Guidelines, public disclaimer, conduct policy, and listserv policy. There were no questions.

4. **Review team roster**

   Mr. Barfield noted that the roster posted on the NERC project page is the current roster approved by the Standards Committee.

5. **Review meeting agenda and objectives**

   Mr. Barfield reviewed the meeting agenda and objectives.

Agenda

1. **Respond to stakeholder comments**

   Mr. Bauer noted that the introduction of the proposed glossary team "Composite Protection System" in the last posting became a problem to the Generator Owners (GO). The team discussed the overarching issues and common themes in the stakeholder comments. Mr. Kuras noted that there were a number of opposing comments where some commenters agreed with certain concepts, but others did not. Mr. Barfield highlighted that the report had been organized to the degree possible by topic. For example, the definitions of Misoperation including the slow-trip, Composite Protection System, reverse power relay concerns, and the investigative action in Requirement R4.

   The team selected definition of "Composite Protection System" comments as the first point of discussion. The team discussed what equipment was within scope of the Protection System, such as, sync check relays for closing in two portions of a system that may have an angular difference between them. The consensus was that this equipment does not provide inputs to the Protection System and are control inputs; therefore, are clearly not within scope. The team discussed what constitutes a Composite Protection System particularly concerning the Generator Owners. Should a loss of field condition be part of the Composite Protection System for a failed bus differential relay? Consensus was that the loss of field is not part of the Composite Protection System for the bus because it is analogous to remote clearing. The Composite Protection System is the protection for its given Element (i.e., bus, generator, line). The loss of field is not protecting the bus, it is protecting the stator; therefore not within the Composite Protection System for the bus.

Mr. Bradish asked the team if mechanical inputs (e.g., vibration sensors) are included within the Composite Protection System or Protection System. For example, work in other NERC projects are addressing equipment that is not defined within the scope of Protection System (e.g., sudden pressure). The team agreed that these are currently not within scope. If added to the definition of Protection System, mechanical inputs would be within scope of both Protection System and Composite Protection System. Mr. Barfield noted to the team that the assigned FERC representative, Juan Villar had contacted him about including sudden pressure relays in the proposed standard. Mr. Barfield took the item as an action point for a follow up phase to this team's work and theorized that the undervoltage load shedding (UVLS) standard drafting team would address sudden pressure or newly revealed issues when addressing the inclusion of UVLS to the applicability of the proposed PRC-004-3 standard.

A few commenters expressed confusion about the use of Protection System and Composite Protection System because they seemed to be used interchangeably within Requirements R1 and R2. Mr. Paglow believed it would be clearer to use Composite Protection System consistently in the requirements; however, some team members disagreed. Several approaches were considered relative to how both definitions work in concert with the requirement language. The team agreed not to change Requirement R1 based on these comments, but decided to add additional information in the Application Guidelines. Mr. Barfield referred the team to Requirement R2 to confirm that the achieved consensus in R1 remained true for R2. Mr. Middaugh suggested adding "Composite" in the main body of Requirement R2. The proposed edit reached consensus.

Discussion around Requirement R2 raised concerns about entity performance. Mr. Sorrells noted that the Requirements have no performance for the case of a "failure to operate" because the entity's BES interrupting device did not operate which is used to initiate performance under the standard. Mr. Middaugh described that entities informally communicate this scenario to the entity that was thought to have experienced a failed Protection System. The concern was that an entity that remotely clears a transmission line would not have a Requirement to notify the other owner. Mr. Middaugh believed that under Requirement R2, Part 2.1 the remotely cleared line for a zone 2, for example, would be a part of the Element's (transmission line) Composite Protection System; therefore, the remotely clearing entity would have an obligation to notify the entity at the other end of the line. Some were concerned that industry would not have the same understanding. The team concurred that to avoid a gap, the entity that had the BES interrupting device operation must have a Requirement to notify the other entity suspected to have a "Failure to Trip" condition. This would require the non-operating BES interrupting device entity to review its Protection System for Misoperation under the proposed Requirement R3. The current wording of the proposed standard has no provision for notifying another entity for the case of "Failure to Trip" because of the way the applicable entity parses through the Requirement Parts (e.g., 2.1, 2.2. and 2.3). If the initiating entity determined that its Composite Protection System operated "correctly," they have no Requirement to notify others. This is the condition that creates a gap in performance and was also identified informally by Boris Voynik, FERC technical staff.

To address this non-operation (i.e., Failure to Trip) gap in performance and the remote clearing communication issue, the team discussed several alternatives and approaches including adding an additional clause to include remote backup clearing in the main part of Requirement R2. Another consideration included having two options (e.g., A and B) where one option would address the shared Composite Protection System ownership and the other where no ownership is shared, but an entity that experienced a remote clearing operation would be obligated to notify the other owner(s). Mr. Paglow noted that remote backup seems to be understood by industry as no comments were submitted questioning "remote backup." Mr. Miller read the Institute of Electrical and Electronics Engineers (IEEE) definition for "remote backup protection" to the team. Mr. Paglow also read the IEEE definition of "backup protection." Mr. Miller noted that IEEE did not have a definition of "local backup" which was used in the definition of "Composite Protection System" in the previous draft of the proposed PRC-004-3 standard.

Mr. Kuras suggested that it might be easier to make the notification automatic, unless the entity can exclude notifying others based on specific conditions. Although some members liked the approach, it was determined to be problematic. Mr. Bauer provided sample text as a new Requirement for addressing the notification gap (i.e., upon a "Failure to Trip") in Requirement R2 for notifying other owner(s) when there is no Composite Protection System joint ownership. The team agreed the concept would work and added it to the proposed standard. The proposed new requirement reads:

> RX. "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that was operated by a Protection System component intended to operate as backup protection for a condition on another Element shall provide notification of the operation to the Protection System owner(s) for which that backup protection was provided.

One team member noted that the Requirement has not addressed the time period for performance which is 120 calendar days. The new and additional proposed Requirement answers the following three questions that were raised as being problematic in the previous Requirement R2; (1) How to notify others upon correct remote clearing (i.e., it would be a correct operation per the proposed standard) when it was someone else's Composite Protection System that led to the remote clearing; (2) how to initiate Protection Systems reviews for an entity that did not experience a BES interrupting device operation (non-operation); and, (3) how to keep the compliance burden low concerning notification of others. The team agreed that the proposed new requirement addresses these questions.

The team discussed the issue of "local backup" within the proposed definition of "Composite Protection System." The concern is whether this term includes or excludes breaker failure schemes. Mr. Middaugh noted that he understands breaker failure as being separate from the Composite Protection System. Most team members also see breaker failure as separate and not protection for Elements, but to protect the system for a breaker not operating (even though some team members argued that a breaker is an Element by definition). Consensus was to remove “local backup” from the proposed definition.

> **Composite Protection System (Draft 3):** The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, ~~local backup~~, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded

Mr. Edwards noted that the clause above “such as” is a list (i.e., for example) that is modifying the wrong word and should modify “complement.” He argued that the examples are better served in the Application Guidelines and do not change the intent if removed from the proposed definition. The team agreed to remove the examples from the definition of “Composite Protection System” and provide examples in the Application Guidelines.

The team discussed industry concerns about the definition of “Composite Protection System,” categories #5 and #6 because “Composite” does not precede “Protection System” in those categories. The initial conclusion is that the two “Unnecessary” categories (#5 & #6) may include Protection Systems not associated with the actual Composite Protection System of the protection that caused the operation. For example, the definition of “Composite Protection System” excludes remote backup clearing. The team discussed the last sentence of the proposed definition and concluded that a simple rephrasing would clarify the intent. The team reached consensus on the following proposed definition:

> **Composite Protection System:** The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided to a remote Protection System is included.

The team discussed reverse power issues raised by numerous comments. One commenter did not want to be limited to protective functions intended to operate as a control function during switching (i.e., programming). The commenter wanted the flexibility to decide whether the operation was a protective or control as a part of its standard procedure. Mr. Paglow notes that this issue goes back to the definition of “Misoperation” concerning the meaning of “Failure to Trip” which when a relay fails to trip, it is a Misoperation.

Mr. Seelke joined the team’s meeting remotely to explain Public Service Enterprise Group’s (PSEG) five major points from the comments in greater detail. The first point was to add an additional “unknown trip” category (e.g., #7) to the Misoperation definition. This category would address their concerns when the entity is unable to fit a particular operation into the current six categories. Mr. Kuras noted that the team’s position is that if the entity cannot determine a Misoperation, that the entity may assume the operation is correct.

Second, Mr. Seelke raised the issue of reverse power (i.e., control functions) among GOs. Specifically, he noted that reverse power relays have a blind spot when operating at a low power factor. His suggestion was to remove these relays from the standard all together. Mr. Kuras noted that the team drafted the standard to carve these relays out of the proposed standard’s applicability when operated in a control manner. This approach was designed to exclude the GO’s Protection System(s) when the generating units are going on and off line in a controlled environment from being subject to reviewing its routine operations for

Misoperation. Mr. Kuras emphasized that the applicability is hinged on the intent of what the GO is doing at the time. Mr. Bauer questioned what backup protection is used beyond reverse power and what does PSEG use. Mr. Seelke responded that he was not sure, but PSEG procedures have defined parameters for their operators. He also noted that PSEG currently reviews shutdowns for Misoperations.

With regard to reverse power and to gather more information, Mr. Miller replayed the February 20, 2014 industry webinar for the team. The team agreed that most of what the team is doing is reiterating or restating the same intent; therefore, decided not to make any substantive changes. Mr. Tatro provided revised text for the Application Guidelines which improved the clarity requested by numerous industry commenters regarding reverse power. The proposed text:

> "In the examples above, the standard is not applicable to operation of the protective relay because it operated as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover."

Mr. Seelke noted the proposed standard is much improved. The third item, he questioned Requirement R4 about determining the cause(s) of Misoperations. He suggests that language be added to Requirements R1 and R3 to find the "cause" because it is not readily apparent to the reader and there is no Requirement for the entity to actually find the "cause." The team later considered the fact that the proposed standard was silent on finding the cause, except when not known. Mr. Barfield theorized that entities may be looking for a Requirement that clearly provides the "cause" to be able to conclusively address it as a step in the process. The team agreed that it was not necessary to have a specific Requirement to address finding the cause.

Mr. Seelke had a fourth comment that the standard should only deal with the investigative actions and not the use of the two calendar quarter period used within Requirement R4. Mr. Barfield noted that the time period was selected to make the Requirement measurable and to more easily calculate the time period as opposed to using days or months. Mr. Seelke provided an example period and Mr. Kuras noted how it would be handled and that the team could add an example to the Application Guidelines.

Mr. Seelke's last comment was about the operation of BES interrupting devices that were unexpected. The team concurred this is unmeasurable and that the restriction in the proposed standard to only review BES interrupting device operations caused by a protection system gets the standard to the same point.

The team had continued debate about the reverse power issue trying to determine the ideal approach. Discussions included how the plant operator would respond to a failure of the reverse power relay during a controlled shutdown. Some team members believed that would be "intervention due to a Protection System failure" as described in Requirement R1, Part 1.1. Other scenarios included where the entity employed two sets of reverse power where one is generally the one used for controlled shutdown and the other for backup protection. Given the variety of schemes used, the team agree there is not an ideal way to address the reverse power issue beyond the way it is addressed in the proposed standard's Applicability section. In short, the team reached consensus that in any case where the reverse power is used (intended) for a control function, such as taking a generating unit off-line, the operation of that Protection System is not applicable to the standard. The Application Guidelines were marked to provide additional information and guidance.

Mr. Kuras asked Mr. Paglow to describe his proposed edits to the definition of Misoperation that he circulated to the team prior to the in-person meeting. He suggested adding "when tripping for protection purposes" and changing "is a Misoperation" to "constitutes a Misoperation" in the main body of the definition. For categories 1-4 and 6, he suggested removing the clause after "…which it is designed" and adding corresponding footnotes. The team was concerned about the changes being substantive. Mr. Kuras noted that the Slow-Trip category needs work based on industry comments. For example:

> **Misoperation (Draft 3):** The failure a Composite Protection System to operate as intended when tripping for protection purposes. Any of the following is a Misoperation…
>
> **Misoperation (proposed edits):** The failure a Composite Protection System to operate as intended <u>when tripping for protection purposes</u>. Any of the following <u>constitutes</u> a Misoperation…

The team openly discussed the above and industry comments and their personal thoughts concerning the definition of "Misoperation." For the Misoperation definition, categories #1 and #2, Mr. Paglow also suggested removing the last sentence as it was redundant. Mr. Tatro theorized that it was a carryover from the work done prior to posting before the team reached consensus on the proposed definition of Composite Protection System. Given there were no questions or comments about it from industry, the team elected to keep it for clarity.

Mr. Bauer raised a concern that the word "intended" in the main part of the Misoperation definition is based on the way the six categories of the definition are written. For example, category #3, Slow-Trip leads the reader to a different conclusion. If the entity's Protection System operated as intended, then it would be a correct operation and that category #3 is forcing the entity to identify it as a Misoperation. The team agreed that is correct. Mr. Tatro noted that if other things happened, the goal is for the entity to identify where the problem is and develop a Corrective Action Plan to mitigate reoccurrence. Mr. Sorrells noted he did not see how the proposed definition of "Misoperation" prescribes performance that is different from what entities are doing based on the current approved version of Misoperation.

Another concern was that Protection System owners may be unaware of specific time requirements to meeting planning standard objectives for the "Slow Trip" category (#3 & #4). Mr. Paglow continued with his suggested definition changes. The team agreed with changes to the "Slow Trip" categories (#3 and #4) after discussion. He also recommended removing the examples "such as a power swing, undervoltage, overexcitation, or loss of excitation" and moving them to the Application Guidelines. Mr. Tatro was concerned that in moving the examples to the Application Guidelines there would be a lack of clarity if the definition were used by another standard and also that the guidelines are intended to be standard specific. To be clearer, the team removed the examples (e.g., power swing, undervoltage, overexcitation, or loss of excitation) and replaced the text with "…if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System." Some team members expressed concern this may confuse stakeholders with "Failure to Trip" where "at least one other Element's Composite Protection System" operated. The difference was clarified that the phrase "if the duration of its operating time resulted in" means that the Protection System still operated and is not a "Failure to Trip."

The team discussed Mr. Paglow's proposed changes to category #6, Unnecessary Trip – Other Than Fault. He suggested the category be further clarified on-site maintenance is meant to include maintenance that is currently going on in real-time. Rather than replace the entire clause with new language, the team considered replacing "on-site" with "real-time." Mr. Middaugh questioned how the case would be handled where maintenance or test personnel left a test switch open that resulted in a failure to trip (i.e., category #1 or #2). The question raised several points about conditions where this causes a potential lack of clarity in what the entity should do. The team noted that additional language needed to be added to Misoperation, category #2 to address the failure to trip:

> "A Protection System failure to operate that is caused by <u>real-time</u> maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation."

Mr. Sorrells brought attention that adding such language was unnecessary because the proposed Requirement R1 requires performance when the BES interrupting device operates; therefore, the team decided to remove the proposed changes to category #2. Likewise with replacing "on-site" with "real-time" because industry commenters did not reveal this as an issue. Placeholders were added to the Application Guidelines to address breaker failure and remote backup protection rather than include them in the definition of "Misoperation" to address confusion over breaker failure and Composite Protection System.

Mr. Bradish suggested that the team be more responsive and provide additional information to Texas Reliability Entity's comment concerning the reason that if the overall performance of the Protection System (e.g., a redundant system) is correct, then it is not a Misoperation. He pointed out that an indicator that a Misoperation did not occur is that the reliability of the BES was not adversely affected. The team agreed. Due to TRE's concern, Mr. Barfield took an action item to discuss how TRE's comment may or may not impact information reported through the proposed NERC Rules of Procedure, Section 1600, Request for Data or Information. Mr. Edwards asked if the team identified any modifications to the standard that might impact the data request. Mr. Barfield noted that he would discuss any data request issues off-line with Mr. Edwards and Mr. Tatro.

The team discussed issues around joint ownership and how that impacts who is notified and who is responsible for identifying Misoperations in either Requirement R1 or R3. A number of scenarios were discussed, such as contractual arrangements between entities. Mr. Barfield noted that entities have the option of registering under a Joint Registration Organization (JRO1) to assign a complete standard to a specific entity; register as a JRO2 which is known as a Coordinated Functional Registration (CFR) to assign specific requirements to another entity. The JRO options are most concrete for compliance and auditing approaches, but are less flexible than an entity having its own contractual agreements.

The team discussed the issues on how or when to judge a Protection System operation as a correct operation or a Misoperation. For example, if an entity cannot determine if the operation is a Misoperation, what should it do? The February 20, 2014 industry webinar noted that entities would need to assume the operation as a Misoperation (R1 or R3) and continue its work under Requirement R4. Another example is just having the entity declare the operation as correct and move on. Mr. Barfield noted that an entity may choose either avenue to address potential Misoperations and that it depended on what is best for reliability. For example, where does the team want entities to focus their resources? If the operation is deemed correct, the entity will have information for future reoccurrences where it can conclusively identify a Misoperation. If the entity is encouraged to err in the direction of Misoperation (i.e., R1 or R3), this may have an unintended consequence of over-reporting problems. Over-reporting may lead to expending both entity and NERC resources on removing Misoperations that are reported and later found correct. It also places the entity unnecessarily into other compliance obligations. The team debated and reached consensus that an operation should be deemed correct to avoid over reporting and that this position is more closely aligned with the intent and language of Requirement R1 and R3 for identifying Misoperations.

The team discussed communication of Protection System operations between the GO and Transmission Owner (TO) with respect to the way the proposed standard is structured. Concerns were raised over how and who will communicate the BES interrupting device operation for conditions where ownership is different and the GO actually operates the BES interrupting device in a control function. The first case, a GO operates the TO's BES interrupting device. Does the TO review this for Misoperation (i.e., R1)? The team debated and concluded that the TO would be in communication with the GO and when the GO operated the BES interrupting device in a control function to shut down the generating unit, for example, the operation would not be applicable to the standard. The team concurred that if the GO identified a problem during a controlled shutdown, as a matter of practice, it would address the problem, but would not be subject to the standard. Also, if the TO's BES interrupting device operates in addition to an expected GO's device, then it would review under Requirement R1 or R3 according to the situation.

Mr. Winston raised concern given the strict reading of R1, it appears that every BES interrupting device operation must be recorded for evidence documentation. He felt regardless of what the posted draft Reliability Standard Audit Worksheet (RSAW) was explaining as the audit approach, it appeared that the standard requires entities to be able to show the complete set of BES interrupting device operations. Mr. Barfield noted that the population of operations subject to review for Misoperation are those which meet Parts 1.1

through 1.3 of Requirement R1. Mr. Winston disagreed because the language describing the BES interrupting device operation is embodied within the main part of Requirement R1. The team did not read the Requirement in the same manner. He was concerned that being able to identify all the operations to which compliance is required under the proposed standard, the GO and TO would need to be involved, but are not currently applicable. The set of operations that are reviewable needs to be clear in that it does not require operating entities to be involved. This issue also pertains to those operations which must be captured where a BES interrupting device operation was caused by manual intervention in response to a Protection System failure to operate. The team did not perceive this as a major concern unless other comments reveal additional information.

2. Revise and review documents

The proposed standard was revised during the course of responding to comments. Other documents were not edited at this time and may need future revision to align with changes made to the proposed standard.

3. Review of the schedule

Mr. Barfield noted to the team that having to post for an additional 45-day ballot would cause them to target an August NERC Board of Trustees adoption rather than a May 2014 adoption.

4. Action items or assignments

Mr. Kuras – Make assignments to the team to complete Question #5.

Mr. Barfield –

- Poll team for conference calls the week of April 7
- Need a review of standards that use "Misoperation" (e.g., EOP-010, PRC-006-1, PRC-003-1, and PRC-022)
- Add professional engineering ("P.E.") designation after each team member's name on the roster.
- Add two calendar quarter example in Application Guidelines according to John Seelke's comments.
- Review guidance for Measures.
- Reach out to:
  - Western Interconnection Compliance Forum (WICF)[3]
  - North American Generator Forum (NAGF)
  - North American Transmission Forum (NATF)
- Data Request

[3] http://www.wicf.biz/

- Talk to NERC Legal about joint ownership issues.
- Talk to NERC Legal about extenuating circumstances.
- Talk to NERC Legal and RAPA about standard changes that may impact the data request.
- Investigate how the change in reporting affects NERC's metrics when no longer reporting Misoperations of one of the redundant Protection Systems where the overall performance is as intended. See Texas Reliability Entity's comments.

Mr. Purdy –

- Work on reverse power examples in Q4 with Dominion staff

5. Webinar topics

- What is covered in a Composite Protection System
- Applicability for GO's control vs. protection
- Cover remote clearing/failure (Mr. Voynik's comment)
- Non-operation of a BES interrupting device – what triggers performance.
- Misoperation Definition
- Slow trip
- Maintenance
- Clarify statements from previous webinar about the assumption when an entity cannot determine whether a Misoperation occurred.

6. Next steps

Mr. Bauer suggested outreach with the WICF Generation Peer Sharing Event on April 15 and 16, which is fast approaching and still has a few seats left. It will be held at PG&E's San Ramon Valley Conference Center in California. There is no registration fee and lunch will be provided – FREE, courtesy of PG&E. The deadline to register is April 2. To register, please click on the following link and follow the instructions: https://www.surveymonkey.com/s/QHG3NLH.

A team member noted that the North American Transmission Forum may be meeting adjacent to the WICF meeting (4/17-18).

7. Future meeting(s)

To be determined based on feedback of assignments on Question #5 from the Consideration of Comments report. If the team is unable to work through the last question via conference call(s), an in-person meeting will be held in late April or early May 2014.

8. Adjourn

The meeting adjourned at 12:05 p.m. ET on Friday, March 21, 2014.