Survey Report

Survey Details

Name 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes | PRC-012-2

Description

Start Date 8/20/2015

End Date 10/5/2015

Associated Ballots

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 IN 1 ST

2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes PRC-012-2 Non-binding Poll IN 1 NB

Survey Questions

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

Yes

No

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

Requirements R1, R2, and R3 pertain to the submittal of Attachment 1 information to the Reliability Coordinator (RC) for the review of a RAS, the RC using Attachment 2 as a guide for performing the RAS review, and the RC approving the RAS prior to the RAS being placed in service. Question 1 is relevant to these activities.

1. RAS review and approval: Do you agree with the RAS review process outlined by Requirements R1, R2, and R3? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

The NSRF propose revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, “Each Reliability Coordinator . . . shall in conjunction with impacted Transmission Planners and Planning Coordinators . . .” The inclusion of Transmission Planners and Planning Coordinators is appropriate because RASs are ‘standing, automatic’ schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review by impacted entities.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Oncor Electric Delivery believes that it is a good idea to have an independent party review any RAS. However, 90 days for the review seems more reasonable since they are just reviewing the scheme.

Additionally Oncor Electric Delivery believes the RAS information required in attachment 1 contains more than is necessary for a review and cannot always be obtained for every RAS. In fact, unless the RAS is an existing system during the review period there are usually no schematics to review so we do not believe it is appropriate to request schematic diagrams. The second bullet under General section I asks for “functionality of a new RAS”, which would be a relay functional diagram that depicts how the scheme works and that would be available during the review process.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. R1 references “each RAS-entity shall submit…”, but there should only be one RAS-entity per RAS, is this correct?

b. The supplemental material of the Standard states that the RAS owners needs to select an RAS-entity or else the RC will select the RAS-entity. This language needs to be in the Standard if it’s going to be enforceable.

c. For the designation of the RAS-entity between different owners, will NERC/FERC/Regions require a CFR or JRO agreement? And what happens if one of the RAS owners is not a NERC registered entity, i.e., not a functional entity? Please describe what evidence needs to be provided to show designation of responsibility to the RAS-entity.

d. Also, most, if not all, new RASs are developed, studied, and reviewed within the long-term Planning Horizon by PCs and TPs. Modifications/retirements to existing RASs have the potential to be developed in the Operating Horizon; therefore, Seminole suggests that R1 be broken up into two requirements, one addressing modifications/retirements which would be specific to the “Operations Planning Horizon” and the second addressing “new” RASs specific to the “Long-term Planning Horizon” and applicable to PCs as well.

e. Can the drafting team define all of the components of an RAS so that “ownership” can be determined, i.e., what equipment makes up an RAS?

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

A. It is unclear why R3 is not structured consistent to R1 even though both requirements are prerequisites for achieving the same objective of "placing a new or functionally modified RAS in service or retiring an existing RAS". Suggest restructuring R3 as follows for clarity and consistency:
"Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, the RAS- entity shall address each issue identified by the RAS review (performed pursuant to Requirement R2) and obtain approval of the RAS from each reviewing Reliability Coordinator."

B. In R1, the RAS review falls within the purview of one or more RC's depending on "the area(s) where the RAS is located." What attributes define the location of a RAS? Should the RAS location comprise of only the station(s) where its remedial action logic processing device(s) is/are installed? Or would the RAS location also include the stations from where the various RAS inputs are telemetered to the logic processing device? Would it also include the station(s) at which the RAS output(s) – that is, remedial actions – are sent? Suggest that the standard provides clear guidance on what comprises the RAS location. Alternatively, suggest using a different RAS characteristic in R1 to avoid subjective and inconsistent interpretations of what comprises RAS location.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC proposes revising R2 to explicitly include the engagement of any applicable Planning Coordinators with wording like, “Each Reliability Coordinator..... shall in conjunction with any Planning Coordinators .....” The inclusion of Planning Coordinators is appropriate because RASs are ‘standing, automatic’ schemes that are evaluated primarily in the planning horizon and by Transmission Planners. In general, Reliability Coordinators do not have planning horizon analysis information or expertise.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. References to the Reliability Coordinator should be changed to Planning Coordinator. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

To remove possible confusion, "on a mutually agreed upon schedule" should be changed to "on a mutually agreed upon schedule between Reliability Coordinators and RAS-entities."

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being "The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area." It is not responsible for the planning or installing a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or Protection System installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed and not a complete formal approval of the RAS. If the RC is to perform the review, we suggest the following rewording for R3:

"Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS."

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance, following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

The owner of any protection scheme should be responsible for the correct design and implementation of the scheme – RAS or not. Just like the design of switching to create a blackstart cranking path by a TOP in EOP-005-2, Requirement 6 must be verified by that TOP, the owner of the RAS should be held to the same expectation that the RAS is correctly designed and implemented. If the SDT still believes that some sort of review is required, then that review should be limited in scope to reviewing the generic content of the RAS design and not delve into the technical depth identified in some parts of Attachment 2.

Using the criteria outline by the SDT in its recent webinar, in addition to the independence of the reviewer and geographic span, the team also mentioned “expertise in planning, protection, operations, equipment”. The attributes of this expertise to the level expected do not currently exist in most RC organizations. RC’s are primarily operating entities (and even then primarily in real-time) and not experts in planning (beyond the operating time frame), protection or equipment. Transmission Owners, Transmission Operators and Transmission Planners normally have that expertise. The FERC acknowledged the limited RC technical expertise in evaluating details of restoration plans in its Order 749, Paragraph 38 (“…basis on which a reliability coordinator rejects a

restoration plan will necessarily be based on generic engineering criteria…"). The review of a RAS by an RC should not be held to a higher expectation due to similar limited expertise with the equipment and systems involved in a RAS.

The "flexibility" for the RC granted in the requirement to designate a third party would seem to immediately invalidate the original assumptions that the RC has the compelling capability to adequately perform the review while meeting the SDT's characteristics of the reviewing entity. To allow this, while still requiring the RC to be responsible for the review, seems like an improper administrative burden and a potential compliance risk that the RC may assume because it had to find an entity more qualified than itself to perform the review. If an RC is not qualified to review all of the items in Attachment 2 then how can it be held responsible for the results of the review?

Regarding the designation of a third party reviewer, clarification needs to be made regarding what it means to "retain the responsibility for compliance." Does this simply mean that the review takes place or that there is some implied resulting responsibility for the correct design and implementation that the RC is now accountable for.

Finally, also regarding the designation of a third party reviewer, is the term "third party" meant to be any entity not involved in the planning or implementation of the RAS?

The alterative to using the RC? Although there appears to be a movement to remove the RRO as a responsible entity from all standards, those organizations through their membership expertise and committee structures more closely match the characteristics stated by the SDT – expertise in planning/protection/operations/equipment, independence by virtue of the diversity of its members, wide area perspective, and continuity. If for some reason the SDT, believes that the RRO still should not be involved then an alternative could be the Planning Coordinator function which should have similar expertise to the Transmission Planners that are to specify/design a RAS per the functional model yet would have some independence which the SDT is looking for.

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

On the whole, Reclamation agrees with the RAS review process outlined in Requirements R1–R3. However, Reclamation believes that RAS-owners should also be listed in Attachment 1 and Attachment 3 and should be notified of all RAS-entity communications with the Reliability Coordinator (RC). Reclamation does not believe that the RAS-entity should be able to release technical information about a RAS-owner's equipment without the knowledge of the RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

Florida Power & Light appreciates the efforts of the Standard drafting Team in consolidating the existing RAS-related Standards into one Standard (PRC-012), however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review RAS's for new or continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best performed at the planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve and maintain the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: No

Answer Comment:

The ISO/RTO Council Standards Review Committee (“SRC”) agrees that the RC should have to approve the use of RAS. Pursuant to the Functional Model, the RC does not have the authority to approve relay schemes. Nonetheless, it is important that the RC be informed of and understand how the RAS impacts the topology of its area of authority, identify and communicate any reliability issues to the RAS proponents, and coordinate with the RAS Entity regarding the in-service date and time of the RAS. We further recommend that M2 and M3 be modified such that acceptable evidence can be a Reliability Coordinator sponsored peer review with impacted Transmission Planners and Planning Coordinators.

Therefore, the SRC proposes that Requirement R3 be revised to:

R3. Following the review performed pursuant to Requirement R2, the RAS- entity shall address each identified issue and obtain concurrence from the Reliability

Coordinator that all identified issues are resolved prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

While the SRC is not opposed to a guideline regarding the performance of RAS evaluations, Attachment 2 is overly prescriptive and does not allow for impacted entities to utilize their operational experience and engineering judgment. The SRC recommends that the introductory paragraph to Attachment 2 be revised to provide greater flexibility regarding RAS evaluations. The following revisions are suggested:

The following checklist provides reliability related considerations for the Reliability Coordinator to consider for inclusion in its evaluation for each new or functionally modified2 RAS. The RC should utilize the checklist to determine those considerations that are applicable to the RAS evaluation being performed; however, RAS evaluations are not limited to the checklist items and the RC may request additional information on any reliability issue related to the RAS

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

With regard to R1, the RAS entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by Planning Coordinator (PC) or Transmission Planner (TP). RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for an RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model

does not support the RC as being the reviewer. The RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1. It is inappropriate for RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity.

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: No

Answer Comment:

As Dominion stated in its previous comments, we believe that RAS should be reviewed and approved in both the planning and operating horizons by designated entities within whose area(s) the Facility (ies) the RAS is designed to protect reside.

Dominion suggests the following specific changes to R1: Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS- entity shall submit the information identified in Attachment 1 for review to the Reliability Coordinator(s) **and Transmission Planner(s) within whose respective** area(s) the **Element(s) or Facility(ies)** for which the RAS is **designed to protect is (are)** located..

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: No

Answer Comment:

See the comment in #7.1. In addition, the Transmission Planner should be a required participant in developing Attachment 1 and at least be responsible for Section II in Attachment 1. Finally, the obligation in R3 that a RAS-entity address issues identified pursuant to R2 is incomplete. R3 should also place compliance obligations on the Transmission Planner and the RAS-owners to participate in addressing any issues under R3.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Regarding Requirement R1, the RAS-entity is not typically qualified to provide some of the information required in Attachment 1, such as Sections II.3, II.4, II.5, and II.6. This information is typically developed by the Planning Coordinator (PC) or Transmission Planner (TP). RAS-owners typically only implement the RAS as functionally required by the PC or TP. The Planning Coordinator should be listed as an applicable entity.

The Planning Coordinator is the correct function to determine where a RAS Scheme is required. The need for a RAS is determined from TPL studies and planned system performance. The standard correctly provides the RC with an opportunity to participate in providing opinion. The NERC Functional Model defines the RC as being “The functional entity that maintains the Real- time operating reliability of the Bulk Electric System within a Reliability Coordinator Area.” It is not responsible for the planning or installation of a Protection System. The NERC Functional Model does not support the RC as being the reviewer. The

RC currently does not review nor have the authority to approve any other facility or protection system installation. Clarification of R3 regarding approval of the RAS after all issues have been addressed should be made. The approval mentioned in R3 could be interpreted as an approval that each identified outstanding issue was addressed not complete formal approval of the RAS. If the RC is to perform the review, we suggest the following:

R3- Following the review performed pursuant to Requirement R2, the RAS- entity shall address each issue identified by the Reliability Coordinators participating in the review and obtain final approval(s) for the RAS from each Reliability Coordinator participating in the review, prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

Regarding Requirement R3 some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1 as mentioned earlier. It is inappropriate for the RAS-entity to assume compliance responsibility for addressing each identified issue. The RAS-owner for the RAS issues should be the responsible entity.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment: PJM supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirement (as per TPL-001-4), are studied and identified by Transmission Planner and/or Planning Coordinator and not by the RAS owner/entity. The RAS owner/entity designs the RAS after TP or PC determines the functional requirements. The information listed in part II of attachment 1 is about functional requirements and can be provided by TP or PC. Most of the information listed in part I is repeat of part II. The rest, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by TP or PC who determined the functional requirements. The information in part III, which is related to the RAS design, is provided by the RAS owner/entity. RAS owners typically only implement the RAS as functionally required by the PC or TP. It is noted that the Planning Coordinator is not listed as an applicable entity and should be. With regard to R3, some of the identified issues would be most appropriately addressed by the PC or TP, especially the items in Section II of Attachment 1.

We suggest that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to RC for review, and b) design aspects, where RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to RC for review.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

We agree with the checklist for the Reliability Coordinator to receive the proper information pertaining to the RAS and conducting a proper analysis. Additionally, we commend the drafting team for addressing the timing requirements in the Requirement R3 Rationale Box. We feel this will give the industry amply of enough time to address any issues identified by the Reliability Coordinator through their analysis.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment:

Florida Power and Light appreciates the efforts of the Standard Drafting Team in consolidating the exsiting RAS-related Standards into one Standard - PRC-012-2, however we disagree with the assertion that the Reliability Coordinator (RC) is the best choice to review the RAS's for new and continued implementation. The RC is responsible for the operation rather than the planning of the BES. RAS design and approval is best done at the Planning level. The Planning Coordinator is responsible for coordinating transmission plans and protection systems and we believe more appropriate to review, approve, and maintain the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

In Requirement R3, the term “shall address” does not necessarily indicate the issue must be resolved as the Supplemental Material indicates. Texas RE recommends strengthening the requirement language to “shall resolve” or “shall implement”.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1. RAS review should be conducted by the Planning Coordinator and not the Reliability Coordinator. Oversight of the wide-area in the planning horizon is the job of the Planning Coordinator. This will be a significant amount of extra work for the RCs who should be focused on near-term operational reliability.

2. R1 should state a time frame the data should be submitted to the RC, such as four month prior to implementation of the RAS. Otherwise, the burden will be placed on the RC to conduct the study on the RAS-entities schedule.

3. There is no requirement to notify impacted neighboring entities. When a RAS is implemented it can have a significant impact on neighboring entities. Neighboring entities need to have an opportunity to study the impact of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

R1, R2 and R3 do not differentiate between the functional aspects and design aspects of RAS. The functional requirements for a RAS, i.e. system conditions and triggering contingencies for which RAS is required as well as RAS actions to meet system performance requirements (as per TPL-001-4), are studied and identified by the TP and/or PC and not by the RAS owner/entity. The RAS owner/entity designs the RAS after the TP or PC determines its functional requirements. Therefore, the information listed in part II of attachment 1 is about functional requirements and can only be provided by a TP or PC in most instances.

Most of the information listed in Part I is repeated in Part II. The remaining information listed, e.g., maps, one-line diagrams, in-service date, etc., can also be provided by the TP or PC, who determines the functional requirements. The information in Part III, which is related to the RAS design, is provided by the RAS owner/entity.

Hydro One Networks Inc. suggests that R1, R2 and R3 and the related attachments be split in two parts: a) functional aspects, where the TP or PC will be required to determine the functional requirements of the RAS and provide relevant information to the RC for review, and b) design aspects, where the RAS owner/entity will be required to design the RAS to meet those functional requirements and provide relevant information to the RC for review.

In addition, it is inappropriate for the RAS entity to assume compliance responsibility for addressing each identified issue. The RAS owner for the RAS issues should be the responsible entity; this would be more in agreement with the assignment of accountabilities in R6.

Please also note our following comments with respect to relaxing the design review for a class of RAS.

Document Name:

Likes: 1 Hydro One Networks, Inc., 3, Malozewski Paul

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

R2 has an option of a four month schedule or a mutually agreed upon schedule. It is understood that setting a goal for a review within the operations time-frame is important, but it seems like the standard is trying to achieve two separate goals at once.

The first goal is to review the proposed change to determine whether it involves a CAP and identifies any current risks to reliability of the system which, as identified

in the standard, might require use of System operating limits until the CAP is complete. This review needs to be completed quickly to minimize risk to the BES, but requires much less effort than a full review of the performance of the new RAS. In this instance four full-calendar months would seem to be too long of a time period.

The second goal is to complete the full review from a planning perspective. Each region already has a review and approval process in place. It seems arbitrary and unnecessary to impose the 4 month requirement rather than allowing the RC to follow a schedule or process it has already established. In this instance the four months would seem too short a time period in many cases due to the way these reviews are conducted (and by whom they are conducted) – so long as the risk to the BES reliability is already understood up-front, there is no reason to rush this portion of the work. In many cases, the RC in question may not possess the necessary staff / skills to perform what is required in Attachment 2, and may need to retain the services of others (consultants or perhaps area PCs or TPs), which will take time.

FMPA believes both issues could be resolved if R2 separated the near-term need to quickly assess BES reliability risk in the Operating Horizon from the long-term need to assess the details of the performance of the proposed scheme – particularly in cases where the proposed change is due to an identified issue with a subsequent CAP. Doing this first step on fast track would then allow each RC to define the schedule for the remaining review as per their regional practices.

Also, it would be beneficial to include all RAS-owners and their contact information in the RAS database.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

(1) We question why the RC was selected as the reviewing entity in this context. RC System Operators are not required to be “familiar with” (Reliability Standard PRC-001) or “have knowledge of” (proposed Reliability Standard TOP-009) the purpose and limitations of a RAS. Moreover, after the RC has conducted its initial review (Requirement R2) and the RAS-entity has addressed the identified issues, there is no timeframe required for the RC to conduct a final review for approval. We suggest rewording Requirement R3 to require both the RAS-entity and the RC to address each identified issue within a mutually agreed upon timeframe and concluded by a final RC review. Documentation regarding

	an approval of the RC following its final review should then be listed as acceptable evidence in Measure M3. (2) We would also like the drafting team to state that an existing SPS will not need to go through the RC approval process even though the new definition of RAS could be applied as a new RAS device. The standard is unclear regarding which equipment will need to go through the RC approval process, existing SPS/RAS or new/changed RAS equipment? One possible solution is to state that all SPS and RAS equipment that are in service on the effective date of the proposed standard are considered RAS going forward and will not be required to go through the RC approval process.
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA believes R2's timeline of four-full-calendar months for RC review of RAS submission is too generous; it is inconsistent with regional practice. BPA proposes two weeks as appropriate, with less potential negative impact. The schedule should be short enough to accommodate the needs of the RAS owners and the "mutually agreed upon schedule" should apply if more time is needed.

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

2. RAS Periodic Evaluations: Do you agree with the RAS planning evaluation process outlined by Requirement R4? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

For R4, we propose revised wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and impacted Transmission Planners and Planning Coordinators."

Again, the inclusion of impacted Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the evaluation.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

We agree the Transmission Planner should periodically evaluate each RAS but there needs to be a mechanism by which the RAS-owners are required to share the RAS information with the Transmission Planner.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: No

Answer Comment:

The process is not clear about the responsibility for a RAS which is activated in multiple Transmission Planner areas such as WECC-1. The standard should clearly specify whose responsibility it is to perform technical studies. APS suggests the following language:

"For a RAS which is activated in multiple Transmission Planning areas, a mutually agreed upon Transmission Planner of one of the multiple Transmission Planning areas shall perform an evaluation of the RAS at least once every 60- full-calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies."

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer: No

Answer Comment:

a. For R4, can the TP merely provide the data to the RAS owners and the RAS-entity report the information to the RC?

b. In R4.2, please give additional detail as to what "adverse interactions" cover?

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

The rationale and/or technical guidance does not make a convincing case for why the periodic evaluation of RAS must be a planning horizon analysis, and thus suited to be performed by Transmission Planner. As currently drafted, R4 seems to have an underlying premise that the periodic evaluation needs to be performed for the near-term planning horizon, which makes the periodic evaluation akin to the typical (future year) planning studies performed by Transmission Planner. However, the rationale for R4 does not provide any justification for the above. In fact, performing a planning horizon analysis is inconsistent with, if not contradictory to, the following reliability need stated in the rationale "A periodic evaluation is needed because (material) changes in system topology or operating conditions that have occurred since the previous RAS evaluation – or initial review – was completed…" Doesn't this imply that the periodic RAS evaluation is for past changes, not the future planned changes? If so, wouldn't the periodic RAS evaluation be more akin to Operational Planning Analysis (OPA) in the operating horizon? Is there a reason why an OPA would not be able to comprehensively address items 4.1 – 4.4 required for periodic RAS evaluation? We note that the existing R4 rationale makes an inadequate claim that "items required to be addressed in the evaluation are planning analyses", which is a weak basis for concluding that "consequently, the Transmission Planner is the functional entity best suited to perform the analyses." Based on all the above reasons, we contend that the reliability objectives of periodic RAS evaluation are more effectively achieved based on an operating horizon analysis like OPA. Therefore, the periodic RAS evaluation lends itself better to be performed by the Transmission Operator (or perhaps even the Reliability Coordinator).

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Suggest clarifying in R4 that the evaluation is a technical evaluation as stated below:
Each Transmission Planner shall perform a **technical evaluation (planning analyses)** of each RAS within its planning area at least once every 60- full-calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

For R4, ATC proposes revising the wording to explicitly include any applicable Planning Coordinators with wording like, ". . . provide the results including any identified deficiencies to the RAS-owner(s), the reviewing Reliability Coordinators(s) and any applicable Planning Coordinators."

Again, the inclusion of Planning Coordinators is appropriate because the Transmission Planner evaluation will be for the planning horizon and Planning Coordinators will generally have the best information and expertise to review the evaluation.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment: The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer: No

Answer Comment: While generally supportive of this standard, I have concerns over assigning longer term assessment to Transmission Planner rather than to the Planning Coordinator.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer: No

Answer Comment:

1.

i. It is unclear why the Transmission Planner would provide results of the evaluation to each of the RAS- owner(s) and not the RAS-entity. A RAS typically operates as a single scheme and thus the RAS-entity can coordinate with all the RAS-owners regarding such evaluation results.

ii. ReliabilityFirst currently reviews each SPS at least once every five years for compliance with our Regional Criteria in accordance with fill-in-the-blank NERC standard PRC-012, Requirement R1. ReliabilityFirst has concerns with the 60 month review cycle in Requirement R4 as there may be instances in which a SPS which was reviewed by RF in the 2000 timeframe could theoretically not be reviewed until the 2020 timeframe. ReliabilityFirst believes a potential gap of 10 years in between reviews may have reliability impact. In order to prevent such a potential gap, ReliabilityFirst recommends the following recommendation for consideration:

a. Each Transmission Planner shall perform an evaluation of each RAS within its planning area at least once every 60- full- calendar- months **[since its last evaluation]** and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any

identified deficiencies. Each evaluation shall determine whether:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: No

Answer Comment:

Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). The SRC believes that a proper, unbiased evaluation of RAS performance should be conducted by an entity that is not in the same organization as the TO and has a broader perspective, which is important because RAS's intended function and operational impact may affect more than one TO and TP. The SRC respectfully asserts that, given the importance of independence and a wide-area perspective, the Planning Coordinator is a more appropriate entity to perform Requirement R4 . The SRC therefore suggests replacing the TP with the PC or, at a minimum, requiring a review of results and provision of feedback by the Planning Coordinator to the Transmission Planner. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

The RAS-entity would be more appropriate to be specified in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Dominion suggests clarifying in R4 that the evaluation is a technical evaluation as stated below:

Each Transmission Planner shall perform a **technical** evaluation (planning analyses) evaluation of each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: No

Answer Comment:

R4 should be modified to include a new part 4.5 that would require the Transmission Planner to identify any performance deficiencies in the RAS as well as alternatives for mitigating or correcting such deficiencies. The RAS-owners would not have the capability to identify alternatives for correcting deficiencies.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

It would be more appropriate to specify the RAS-entity in R4 instead of the RAS-owner.

The RAS-entity and the RAS-owner should be provided with the results of the review. The PC may be more appropriately qualified to review certain RAS than the TP. Consider revising R4 to read “Each Transmission Planner shall evaluate…”.

Add wording to the Rationale for Requirement R4 to clarify that the intent is not to evaluate all RAS at the same time, but that each RAS is to be evaluated on a 60 full calendar month cycle.

Would the Planning Coordinator ever perform this evaluation instead of the Transmission Planner?

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment: PJM supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: How would a scenario be addressed in which a RAS spans two or more Transmission Planner areas?

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment:

TANC has concerns with the current language in R4 because appears to assume that a RAS exists within a single planning area. NERC has not defined the term "planning area", which creates ambiguity in the requirement's language that states "Each Transmission Planner shall perform an evaluation of each RAS within its planning area." This ambiguity is further compounded in circumstances where a single RAS exists within the footprints of multiple Transmission Planners (and Planning Coordinators). In such cases, it is unclear which Transmission Planners associated with the multiple RAS-owners for a single RAS would have responsibility in accordance with this standard.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

We generally agree with the process outlined by R4, but reiterate our comment that the Planning Coordinator, NOT the TP, should the entity responsible for this requirement.

Many Transmission Owner organizations also perform the transmission planning function and as such, are also registered as the Transmission Planners (for the assets that they own). A proper and unbiased evaluation of the RAS performance should be conducted by an entity that is not in the same organization as the TO and has a wider perspective than the TO and TP. And since the RAS intended function its operational impact may affect more than one TOs and TPs, a PC is the most appropriate entity to perform this task than the TP, both from an independence and a wide area perspectives. We therefore suggest replacing the TP with the PC. This proposal is consistent with the basis for assigning R2 to the RC rather than the TOP.

	The RAS-entity and the RAS-owner should be provided with the result of the review. The PC may be more appropriately qualified to review certain RAS than the TP.
Document Name:	
Likes:	0
Dislikes:	0

Richard Vine - California ISO - 2 -

Selected Answer:	No
Answer Comment:	The California ISO supports the comments of the ISO/RTO Standards Review Committee
Document Name:	
Likes:	0
Dislikes:	0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: No

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of

each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

We feel that the Transmission Planner also conducting an analysis will help address changes to the RAS which could impact the BES. Additionally, we like the fact that the analysis can be performed earlier if changes to the systems topology or system operating conditions has a potential impact on the BES (as mentioned in the second paragraph of the Rationale Box for Requirement R4).

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE asks the drafting team to consider adding the Planning Coordinator to Requirement R4 for instances where a RAS covers multiple Transmission Planner areas. The current practice the ERCOT region is ERCOT conducts the 5-year review of each RAS; however, ERCOT is the Planning Coordinator, not a Transmission Planner.

Texas RE asks the drafting about the term “60-full-calendar-months” in Requirements R4 and R6. The term is not defined and is not consistent with other standards and requirements. PRC-006 indicates five years, PRC-010-1 indicates 60 calendar months, and PRC-014 indicates five years. Texas RE recommends not introducing new terms and to be as consistent as possible. Is the SDT defining a “full calendar month” or “calendar year”? The RSAW is not the place to define a new term and the definition is different than terms used in PRC-005. This definition is misleading to those reviewing the document and could potentially exacerbate reliability issues nearly seven years based on the “definition” provided in the Note to Auditor section of R4 in the RSAW.

The intent of Requirement R9 should be to update once per year not once per 729 days (2 years minus 1 day) which would be allowable by the definition of full calendar year as stated in the RSAW.

Texas RE recommends defining the term “planning area”. It should be prescriptive enough to include GOs and DPs that are RAS-owners, i.e. generator owners or distribution providers that own all or part of a RAS. In Requirement R4, by default a Generator Owner or Distribution Provider owned RAS would be within a Transmission Planners planning area, correct? Please confirm or give

specifics as to why a GO or DP owned RAS would not be within a Transmission Planners planning area.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RAS owner must review the RASs in R4, R5, R6. Nowhere does it give the reviewing Reliability Coordinator the authority to dispute the evaluation in R4, dispute the analysis in R5, and require changes to the corrective action plan in R6. RC is just provided the results of analysis but is not given any authority to do anything with them.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Although Hydro One Networks Inc. agrees with the evaluation process, we emphasize (as described above in Q1) that the evaluation of each new RAS must also be required from the TP or PC before the RAS is approved and implemented by the RAS owner/entity. We recognize that it is inconsistent to require the initial assessment of a RAS from a RAS owner/entity (in R1), and the subsequent/periodic assessments from a TP (in R4).

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: Yes

Answer Comment:

Recommend changing 60 full calendar months to 5 calendar years, to allow the RAS evaluation to fit within the annual Planning Assessment process which may vary from year to year.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

(1) We believe 60 calendar months is an appropriate amount of time to conduct RAS periodic evaluations. However, we do not believe the TP has sufficient visibility outside of its area to determine if the BES will remain stable or the occurrence of a Cascading outage will be minimized following the inadvertent operation of a RAS from any single RAS component malfunction. These “wide-area” views are only available to the PC. We believe the requirement should be rewritten to include the PC as an applicable entity for these technical evaluations.

	(2) We have concerns that the requirement does not identify what events will trigger when the clock begins on the 60 calendar month timeframe. We ask the SDT to clarify when the clock starts for these periodic evaluations – is it after the initial installation, after the latest modification to RAS functionality, or following a response to a CAP?
Document Name:	
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

3. RAS Inadvertent Operation: Do you agree with Requirement 4 Part 4.3 and Attachment 1 which stipulates that RAS inadvertent operation due to a single component malfunction still satisfies the System performance requirements common to TPL-001-4 P1-P7 events listed in Parts 4.3.1-4.3.5? (Note that this requirement remains the same as PRC-012-0 R1.4 except for the allowance for designed-in security that would prevent RAS inadvertent operation for any single component malfunction). If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

Clarity is needed in R4 as to exactly what the trigger is for the 60-full-calendar-months periodic review. Is it tied, perhaps, to the in-service status? In addition, rather than a 60 full month periodic review, AEP suggests a “5 calendar year” review. This would allow flexibility for an entity to integrate this work into its annual planning cycle.

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment:

Needs further clarification. The Transmission Planner or the group that *owns* the RAS should be responsible for the evaluation, coordination and testing of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Recommend deleting Part 4.3 since we find it hard to conceive how the inadvertent operation of RAS can result in unacceptable system performance when the primary motivation for installing any RAS is to achieve acceptable system performance. We acknowledge that inadvertent RAS operation is undesirable, but we also recognize that it is fundamentally the same as a RAS misoperation. And therefore, any adverse reliability impact due to inadvertent RAS operation would get addressed in R5 during RAS operational performance analysis. Consequently, we do not see any reliability risk, and thus no associated compelling need, to identify the potentially unacceptable system performance based on simulations/analyses performed for periodic RAS evaluation using models that reflect “typical” rather than actual operating conditions. Although we agree with the goal of a robust RAS design that is not susceptible to RAS misoperation caused by the malfunction of a single component, we also believe this objective is effectively accomplished by any corrective action plan spawned by the RAS operational performance analysis in R5.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however and we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System

	Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a requirement such as those removed by Paragraph 81 in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.
Document Name:	
Likes:	0
Dislikes:	0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:	Yes
Answer Comment:	Consider adding 4.3.6 “Frequency Trigger Limits (FTLs) shall be within acceptable limits as established”
Document Name:	
Likes:	0
Dislikes:	0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important; however, we suggest that 4.3.1, 4.3.2, and controlling system separation should be the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings.” Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2, we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES, then the RAS should not be subject to additional requirements when the inadvertent operation likely will only have a localized effect. The addition of this unnecessary language in R 4.3.3, 4.3.4, and 4.3.5 may result in local RAS having increased design complexity, additional components that may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, whose inadvertent operation could result in Cascading, System Separation, or instability, be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS, subjecting it to unnecessary additional design requirements.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important however we suggest that only 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood however if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in R 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS which have a wider impact, whose inadvertent operation could result in Cascading, System Separation or instability be subject to this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: No

Answer Comment:

Dominion concurs with the idea of an inadvertent operations test; however R4.3.5 transient voltage response should not be part of that test. Preventing FIDVR is only necessary to prevent cascading due to motor stalling (an unlikely outcome) which is addressed under R4.3.2. Dominion believes that slow transient voltage response that does not lead to cascading and is a customer power quality issue and not a reliability issue.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer:

Answer Comment:

No comment.

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Part 4.3 addresses inadvertent operation and addresses security of the RAS. This is important. However, we suggest that only sub-Parts 4.3.1 and 4.3.2 as well as controlling system separation are the only aspects that are needed. We do not understand the intent of sub-Part 4.3.3 “applicable facility ratings”. Is this normal, emergency, DAL (drastic action limit), etc.? In Attachment 2 we agree that inadvertent operation needs to be understood. However, if that inadvertent operation does not cause one of the three significant adverse impacts to the reliability of the BES then the RAS should not be subject to additional requirements which likely will only have a localized effect. The addition of this language in sub-Parts 4.3.3, 4.3.4, and 4.3.5 unnecessarily may result in local RAS to have increased design complexity, additional components which may increase the likelihood of misoperation (decreasing the reliability of the RAS) and excessive costs. We suggest the SDT consider that all RAS that have a wider impact, those whose inadvertent operation could result in Cascading, System Separation or instability be subject to

	this standard and its design requirements. To place these requirements as written on all RAS would be of little or no benefit to achieving an adequate level of reliability on the BES, and based on this we would characterize this as placing a Paragraph 81 requirement in the standard. Furthermore, this could actually be a detriment to the reliable operation of a local RAS subjecting it to unnecessary additional design requirements.
Document Name:	
Likes:	0
Dislikes:	0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of an inadvertent operation may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

An inadvertent operation in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

1. Cascading
2. Uncontrolled System Separation
3. Instability

When the criteria mentioned above is not met a secure design will be required.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

The SDT may want to consider adding “Applicable System Operating Limits shall not be exceeded” as a sub-bullet to Requirement R4.3.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

FMPA agrees with the intent of R4.3 – that construction of devices/systems as an integral part of the BES should be held to same standards as construction of physical facilities. However, we believe there is a problem with the wording of the first sentence. It is possible to read the first sentence to be requiring that inadvertent operation of the RAS due to a single component malfunction be studied as a planning event regardless of whether the system is designed to prevent such an event from occurring. FMPA believes the intent of the language

	is that items 4.3.1 through 4.3.5 only apply if single component malfunction does actually produce an operation of the RAS. If this were not true (e.g. if the language in R4.3 was requiring the study of the inadvertent RAS operation against the criteria in 4.3.1 through 4.3.5 regardless of whether a single component malfunction could actually cause the RAS to operate), the language would essentially be requiring that TPL-001-4 Planning Event criteria be applied to what amounts to an Extreme Event. This is partly because of the use of the term “malfunction” as opposed to “failure”. This is not consistent with TPL-001-4 which refers to protection system “failures”. This is an important distinction because typically protection systems are designed such that if a component fails, it does so without issuing a false trip. A malfunction can be interpreted to mean a large number of absurdly unlikely things which are over and above the level of rigor required by TPL-001-4. FMPA understands that the SDT desired to consider the use of non-“protection system” control devices using this standard, but the language as written does not allow those entities that are using protective devices to take credit for basic design principles such as redundancy. Suggest either expressly allowing entities to take credit for redundancy, switching to using the term “failure” or both.
Document Name:	
Likes:	0
Dislikes:	0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

Certain aspects of the TPL-001-4 P1-P7 events identify actions under a steady state or a stability assessment. We have concerns that applicable Facility Rating exceedances and BES voltages deviations, as identified with TPL-001-4, are only applicable under steady state conditions. We recommend the SDT modify Requirement R4 to identify these references within the context of a steady state assessment, instead of a transient state, to align with existing NERC standards.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirement R4 mandates that the Transmission Planner perform a technical evaluation (planning analyses) of each RAS at least once every 60 full calendar months to verify the continued effectiveness and coordination of the RAS, including BES performance following an inadvertent operation and single component failure of the RAS. Questions 2, 3, and 4 pertain to these topics.

4. RAS Single Component Failure: Do you agree with Requirement 4 Part 4.4 and Attachment 1 which stipulates that any RAS intended to satisfy System performance requirements in a TPL standard must still satisfy those requirements when experiencing a single component failure? (Note that this requirement remains unchanged from PRC-012-0 R1.3.) If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

The NSRF recommends two modifications to Part 4.4.:

One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment: Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

We do not agree that the “single component failure” requirement should apply to **all** RAS installed to satisfy TPL performance requirements, by completely disregarding the severity of adverse system impact resulting from the RAS failure to operate. In other words, we are advocating that due regard be given to the RAS classifications/types existing in NPCC, WECC and TRE regions, as well as the recommended RAS/SPS classifications in the SAMS-SPCS white paper. Using the RAS nomenclature proposed in the white paper, we recommend that the “single component failure” requirement be limited to Type PS (Planning Significant) schemes only. Excluding the Type PL schemes, like the accepted exclusion for “safety net” (Type ES/EL) schemes, does not necessarily compromise Adequate Level of Reliability in the BES. We recognize that this approach will require judicious selection of the demarcation criteria between

Significant (Wide Area) versus Limited (Local) schemes – however, the existing NPCC and/or WECC demarcation criteria may serve as a reasonably good starting point. Lastly, we disagree with the claim that Part 4.4 remains unchanged from the existing R1.3 in PRC-012-0 – although both may have essentially the same verbiage, the context and the scope of applicability are widely different. While the existing R1.3 may be rightly interpreted to allow discretion to the RRO to determine which RAS/SPS "Types" must be subject to the more robust design that is not degraded by "single component failure", Part 4.4 takes away that discretion by virtue of being a continent-wide standard. There is no factual evidence to suggest that the failure-to-operate of any Local/Limited RAS has resulted in unacceptable/adverse BES performance to warrant "raising the bar" on applicability of "single component failure" requirement.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of
the RAS “following” an inadvertent operation since this is covered by R5. The below statement from
the rationale for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform
a technical evaluation “following” an inadvertent operation.

Copied from Rationale for R4:
The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination
of the RAS, as well as to verify that requirements for BES performance following an inadvertent RAS
operation or a single component failure in the RAS continues to be satisfied.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends two modifications to Part 4.4.

One modification is to explicitly include “option c” in the Implementation section of the Supplemental Material associated with the Standard. The revised wording could be, “A single component failure in RAS, when the RAS is intended to operate, or alternative automatic actions back up the failures of single RAS components . . .” Including text about the alternative option in the standard, rather than the Supplemental Material would assure that it cannot be dismissed by an auditor.

The other modification is to remove the unnecessary linking of R4.4 to TPL-001-4 performance requirements with linking to the performance requirements already expressed in R4.3 of PRC-002-2. The revised wording could be, “. . . satisfies the same performance criteria given in Part 4.3”. This change makes the performance requirements of Part 4.3 and Part 4.4 consistent with each other and subject to changes in the PRC-012-2, rather than independent changes in another NERC standard.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, it does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment.

The regions should each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL- 001- 4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- o Cascading
- o Uncontrolled System Separation
- o Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Please affirm this understanding: For single component failure, a RAS must still satisfy System performance requirements.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. While the TP may have some familiarity with the design of the RAS or with the Operating Procedures in place, they do not know or need to know the specifics of a single component failure. The TP just needs to know the ramifications of an overall RAS operation failure or inadvertent operation. Currently, standards PRC-012-0 and PRC-012-1 R1.3 contain a single component failure design requirement. When these standards were approved by the NERC BOT, there was no NERC BES definition nor was there an approved definition of a RAS. We believe that had the full implication of the costs to be borne by the industry and the subsequent minimal or no reliability benefit associated with this (local impact only schemes) had been recognized, the standard would not have been approved by the NERC BOT. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these types were local and these categories were developed to allow the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, PRC-012-0 and PRC-012-1 only require a single component failure review and design

requirement at the time of review. PRC-014-0 and PRC-014-1, which are the SPS/RAS assessment standards, currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition, it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and the necessary level of reliability and security has been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS, which do not meet the requirement, would need to be redesigned, undergo outages, and then have revisions made to bring them into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL- 001- 4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it, we propose the following:

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability"

The above modification would provide the necessary level of security and reliability to the BES. This ensures that RAS installed on the BES or installed to meet TPL requirements would only be required to meet Part 4.4 when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: Yes

Answer Comment:

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment: See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment: Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP, although may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, the unapproved standard PRC-012-0 and -1 R1.3 contains a single component failure design requirement which is currently unapproved by FERC and the applicable governmental authorities in Canada. When these standards were approved there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved. Further, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has no cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their

periodic assessment. The SDT has gone, in our view, unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperations studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken and then have their revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL- 001- 4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if the SDT is unwilling to remove it we would propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate,

does not result in any of the following conditions on the BES:

- o Cascading
- o Uncontrolled System Separation
- o Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or to meet TPL requirements would only be required when the RAS operation is critical and any inadvertent operation results in a significant impact to the BES.

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: No

Answer Comment:

Dominion believes that redundancy should not be required for a RAS designed for events such as TPL-001-4 P4 (stuck breaker) or P5 (relay failure event). The design should not have to consider two failures which is improbable. As an analogy, in places where there is no RAS scheme, there is no requirement to test a P4 stuck breaker event and then assume that the breaker failure relay does not work, essentially combining P4 and P5 together. Designing a redundant RAS for breaker failure could require installation of two breaker failure relays per breaker to initiate the RAS and maintain complete redundancy. This leads to excessive complexity which can hurt reliability.

Additionally, Dominion suggest adding clarity to indicate the intent of R4 is not to evaluate the performance of the RAS “following” an inadvertent operation since this is covered by R5. The rationale statement for R4 can be misinterpreted to imply R4 requires the Transmission Planner to perform a technical evaluation **“following”** an inadvertent operation.

	Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.
Document Name:	
Likes:	0
Dislikes:	0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer:

Answer Comment:

No comment

Document Name:

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Requirement R4 Part 4.4 is problematic for a number of reasons. First, placing this requirement on the Transmission Planner does not conform to the responsibilities or abilities of the Transmission Planner. The TP may have some familiarity with the design of the RAS or with the Operating Procedures which may be in place, but does not know or need to know the specifics of a single component failure, just the ramification of an overall RAS operation failure or inadvertent operation. Currently, Part R1.3 of standards PRC-012-0 and -1 contains a single component failure design requirement. When these standards were approved by the NERC BOT there was no NERC BES definition nor was there an approved definition of what a RAS is. We believe that had the full implication of the costs to be borne by the industry been recognized and subsequent minimal or no reliability benefit associated with meeting that requirement for local impact only schemes, the standard would not have been approved by the NERC BOT. Furthermore, the System Protection Coordination Subcommittee of NERC had specifically noted and suggested that 4 types of RAS

are on the BES. Two of these were local and these categories were developed to afford the SDT to tailor specific and appropriate reliability and security requirements on these local type schemes. To broadly apply these more stringent requirements to all RAS on the new BES with the new RAS definition has little cost benefit. In addition, the existing PRC-012-0 and -1 only require a single component failure review and design requirement at the time of review. PRC-014-0 and -1, which are the SPS/RAS assessment standards currently do not require the Transmission Planner to include a requirement such as Requirement R4 Part 4.4 in their periodic assessment. The SDT has gone unnecessarily beyond the intent of the current standards in this regard.

In addition it should be noted that all existing RAS have gone through regional reviews and been approved for implementation. These existing RAS may not have met the existing single component failure requirement due to the revision of the BES. The regions each have a process for ensuring the reliability of the BES, and that the necessary level of reliability and security had been met at the time of approval. Furthermore, misoperation studies have not indicated that there is a reliability need to incorporate single component failure design into local systems. These local RAS which do not meet the requirement would need to be redesigned, outages taken, and then revisions made to come into compliance. This, in and of itself would represent a risk to the operation and reliability of the BES.

Requirement R4 Part 4.4 currently states;

"4.4 A single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL- 001- 4 or its successor) as those required for the events and conditions for which the RAS is designed."

We suggest Part 4.4 be removed. However, if not removed, we propose the following:

4.4 A single component failure in the RAS, when the RAS is intended to operate, does not result in any of the following conditions on the BES:

- Cascading
- Uncontrolled System Separation
- Instability

The above modification would provide the necessary level of security and reliability to the BES. Ensuring that RAS installed on the BES or installed to meet TPL requirements would only be required when the RAS operation is critical, and any inadvertent operation results in a significant impact to the BES.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment:

Single component failures should exclude station dc supply and some portions of communications systems (e.g., microwave towers and multiplexing equipment). Such exceptions have existed in the industry.

For a single component failure, it is unclear why the requirement was changed from simply having to meet the performance requirements defined in TPL standards to having to meet those required for the events and conditions for which the RAS is designed.

In the Q & A document, section 5, page 4, how can arming excess load and generation not impact reliability? TPL footnote 9 notes that “the planning process should be to minimize the likelihood and magnitude of interruption.” RAS entities should be allowed to consider whether a 100% chance of tripping too much load/generation in the event of correct RAS operation really meets the intent of TPL. In some cases, allowing a single point failure to degrade the performance of the RAS is a better overall choice for minimizing total probability of interruption.

In the Q & A document, section 5, page 4, what kind of automatic actions are referenced? As the NERC reliability standards have evolved, the classification of RAS has expanded from just very high complexity protection schemes to now include many kinds of routine automatic actions. Almost any automatic action used to mitigate a TPL violation would become a RAS by virtue that it is used to meet requirements identified in a NERC Reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

At the present time there are RAS in service that have a limited local impact. To universally apply the same design criteria to all RAS regardless of their impact on BES in case of failure to operate may have no cost benefit in the case of the RAS installed to address local problems.

We propose the following to be included in the standard:

The failure of a RAS to operate does not result in any of the following conditions on the BES:

1. Cascading
2. Uncontrolled System Separation
3. Instability

When the criteria mentioned above is not met a redundant design will be required.

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable
2. Cascading or Uncontrolled System Separation shall not occur

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

When a RAS is used to respond to an event, e.g. category P1 in TPL-001-4, its failure should be considered to be a more severe event, just as in TPL-001-4 the failure of a breaker or protection relay following a P1 event is recognized as “Multiple Contingency” (category P3 and P4). For this reason, the system performance with a RAS failure should not be required to meet the same requirements (defined in TPL-001-4) as those for the original event.

We suggest that the system performance requirement in case of failure of a single component of a RAS be limited to the following:

1. The BES shall remain stable

2. Cascading or Uncontrolled System Separation shall not occur

Please also see the following comments for relaxing the requirements for a class of RAS.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

We recommend that the SDT consolidate the numerous sub-parts in Requirement R4, as they are confusing to both registered entity and auditor.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Requirements R6 and R7 pertain to the development and implementation of Corrective Action Plans (CAPs). Question 5 addresses these requirements.

5. Corrective Action Plans: Do you agree that the application of Requirements R6 and R7 would address the reliability objectives associated with CAPs? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer: No

Answer Comment:

We suggest that the RAS-owner be removed from the Requirements, and that only the RAS-entity be subject to these Requirements. See below for more comments.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP believes R6 should be further revised to clarify exactly when the “six calendar months” begins. We suggest revising it to state ”Within six-full-calendar months of *the RC* being notified of a deficiency…”

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: No

Answer Comment:

The NSRF recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and impacted Transmission Planners and Planning Coordinators". The inclusion of Transmission Planners and Planning Coordinators is appropriate because these entities will generally have the best planning horizon information and expertise to review the CAP.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

There appears to be a gap between R6 and R7, from the point where each RAS owner submits a CAP to its RC, and then implementing the CAP. There should be a requirement placed upon the RC where a review of the CAP is completed and feedback provided to the RAS owner.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment: The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: No

Answer Comment:

R6 and R7 should specify a CAP is created only if deficiency is on the RAS-owners part of the RAS. As written, all RAS-owners would be responsible for submitting CAPs if a single deficiency was identified on just one part of the RAS. As written, a RAS-owner would be responsible for writing a CAP and implementing the CAP for something they may have no control over, if the deficiency is on another RAS-owners part of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Although the Corrective Action Plan (CAP) does address the reliability objectives it is unclear on the responsibilities of the parties involved. As the requirement is written, the Owner must submit the corrective action plan. There is a little confusion on any RAS that have multiple owners. Would ALL the owners need to submit a CAP or only the owner of the equipment in question? SRP recomends clarifying and possibly designating operator as the one to submit the CAP.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment: Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

ATC recommends revising R6 to explicitly include the Planning Coordinator with working like, ". . . submit the CAP to its reviewing Reliability Coordinator and any applicable Planning Coordinators". The inclusion of Planning Coordinators is appropriate because Planning Coordinators will generally have the best information and expertise to review the CAP.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall

participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the PC (we feel that the PC is appropriate as discussed in comments on R1) be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Planning Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-entity. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Also there may be a need for an additional requirement to notify the PC and TOP when the CAP has been completed, and the RAS is performing correctly. We will leave this for consideration by the SDT and believe this brings specific closure to any RAS deficiency.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: No

Answer Comment:

As mentioned in our previous comments, Peak recognizes that the RC or TOP may impose operating restrictions to ensure reliability until the RAS deficiency is resolved but maintains that the CAP should be reviewed by an independent party to assure that it addresses the reliability issues in a reasonable timeframe. . For example, a CAP could be created with an unreasonable timeframe that unnecessarily extends a reliability issue. This independent review by the RC and subsequent required action by the RAS-entity exists for new RAS but not for CAPs, which appears inconsistent with the intent of the Standard. A process similar to that described in R2 and R3 should also apply to CAPs and not just new and functionally modified RAS.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We suggest the following rewording:

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall develope a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).”

R6 should reflect that it is either solely the RAS owner’s responsibility **or** both the RC and RAS owner must have responsibility and “participate” in developing the CAP together. If the CAP requires mutual participation to develop, then both parties (the RAS owner AND the RC) must have compliance responsibility.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation suggests that the RAS-entity should be responsible for the Corrective Action Plans (CAPs) called for in requirements R6 and R7. Each RAS-owner should not be responsible for developing CAPs and coordinating them with the Reliability Coordinator (RC) because this could result in duplication of efforts or inconsistent corrective actions. As outlined in the Technical Justifications, "[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS." When there are several owners involved in a RAS, the RC should communicate with the RAS-entity as one point of contact to ensure that an overall CAP addresses any RAS deficiencies.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer: No

Answer Comment:

The SRC agrees that the RAS entity should develop Corrective Action Plans to evaluate RASs to address issues and/or deficiencies identified by their evaluations, but would suggest that such entities be required to provide the Corrective Action Plans to their Reliability Coordinator ***and Planning Coordinator*** for review.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Attachment 1, Section III-Implementation states, “5. Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes clarification is needed to establish “full calendar months” versus “months”.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: No

Answer Comment:

See the comments in #2, which is critical to R6. Furthermore, the team should modify the R6 phrase as shown below:

"…each RAS-owner shall participate in developing a Corrective Action Plan with the RAS-entity which shall and submit the CAP to its reviewing Reliability Coordinator…."

This will result in one RAS-entity submitted CAP to the reviewing RC.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

“Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).”

As written, R6 doesn’t clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner and affected

Reliability Coordinator(s) shall develop a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s).

Also, there may be a need for an additional requirement to notify the RC and TOP when the CAP has been completed, and the RAS is performing correctly. This should be considered by the SDT. This brings specific closure to any RAS deficiency.

Requirement R5 stipulates that the RAS-owner identifies deficiencies to its reviewing RC. Suggest R6 be revised to read:

"Within six-full-calendar months of identifying or of being notified of a…"

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: No

Answer Comment: ERCOT supports the comments submitted by the ISO/RTO Council.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: No

Answer Comment:

TANC has concerns with the current language in R5, R6, and R7, because it appears these requirements would assign the same or similar responsibilities to "each RAS-owner" when a single RAS operates or fails to operate as expected. In circumstances where a single RAS has multiple RAS-owners, the current language would potentially create overlapping responsibilities to analyze the RAS performance and develop/implement a Corrective Action Plan. It seems that these responsibilities established in R5, R6, and R7 would be more appropriately assigned to the single RAS-entity for a RAS rather than to each RAS-owner.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

Requirement R6 reads as follows:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a

Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability

Coordinator(s)."

As written, R6 doesn't clearly assign the responsibility to the RAS-owner and only states they shall participate. Standard requirements need to be specific on who is

responsible for what, and when. We also suggest that any CAP being submitted to the RC be a “mutually agreed upon” CAP. To address this issue we suggest the following:

Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to

Requirement R4 or Requirement R5, each RAS- owner shall develop a mutually agreed upon

Corrective Action Plan (CAP) with all affected Reliability Coordinators and submit the CAP to its reviewing Reliability Coordinator(s).

We suggest that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states this but it needs to be clear in the requirement. Irrespective of complexity, the need to collaborate with others and hire consulting services, the responsibility should rest solely on the RAS-owner.

Requirement R6 states, “Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…”, however, a notification does not come out of R5 since the applicability to both R5 and R6 is with the RAS owner.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: No

Answer Comment: The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE is concerned there could be an extended time frame where a RAS with a known deficiency will be in service since the requirement to develop a Corrective Action Plan (CAP) is do so within six months. Texas RE is also concerned there is no defined time frame for implementing the CAP.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The RC needs to be given the authority to reject the CAP, or suggest changes to the CAP.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. believes that as quoted below, R6 does not clearly assign the responsibility to the RAS-owner and only states that they "shall participate".

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)."

Standard requirements need to be specific on as to who is responsible for what, and when. We also suggest that any CAP being submitted to the RC be a "mutually agreed upon" CAP. To address these issues, we suggest revising the wording to read the following:

"Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirements R4 and R5 state that each RAS- owner shall develop with all affected RCs, a mutually agreed upon Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)". However, Hydro One Networks Inc. suggests that the full responsibility of the development of the CAP rest with the RAS-owner. The rationale box states that the full responsibility of the development of the CAP rests with the RAS-owner, but this needs to be clear, and explicitly stated in the requirement as well. Irrespective of complexity, the need to collaborate with others, hire consulting services, etc., the responsibility should rest solely on the RAS-owner.

Requirement R6 states, "Within six- full- calendar months of being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5…", however, Hydro One would like to point out that a notification does not result from requirement R5 since the applicability to both R5 and R6 is with the RAS owner themselves.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

The RAS-entity should be included in Requirements R6 and R7 in a coordinating role between the RAS-owners and the TP and/or RC. It should be made clear that the RAS-owners are only responsible for their portion of the RAS.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

We disagree with the SDT that there needs to be two requirements to cover CAPs. These requirements should be consolidated and simplified to avoid unnecessary confusion and potential compliance impacts. Furthermore, CAPs are administrative in nature and we recommend removing these requirements under Paragraph 81 Administrative criteria.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

6. Implementation Plan: Do you agree with the Implementation Plan? If no, please provide the basis for your disagreement and an alternate proposal.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment: The requirement R7 is very ambiguous about the time-frame for implementing a corrective action plan. Who approves the proposed schedule?

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

SRP notices possible confusion on the implementation for R4 and R8. The rationale for R4 and R8 state that the 60 month time period begins on the effective date of the standard. However, the implementation plan does not state that similarly. There is potential confusion for this as many entities are likely to attempt to have their evaluations and functional tests completed by the effective date.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: No

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer: Yes

Answer Comment:

Peak interprets the Implementation Plan as grandfathering in all existing RAS, which means review and approval of existing RAS is not required – only for new or modified RAS. The revised Standard does not address existing RAS, and therefore neglects any potential reliability issues associated with them. Peak seeks clarity on this issue.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

See comment in no. 7.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. TFSP suggests adding the language used in the Rationale box for R4, which says: “Sixty- full- calendar months, which begins on the effective date of the standard pursuant to the implementation plan…”

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer: No

Answer Comment:

The effective date in Implementation Plan should be increased from 12 month to 36 months after the first day of the first calendar quarter after the date the standard is approved. This reason for this delay is that standard establishes a new working framework between RAS-owners, RAS-entities, TPs, and RCs. That itself will involve considerable start-up effort. In return for this added delay, the first periodic review of each RAS under R4 could be due within 36 months, with subsequent reviews every 60 months.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Suggest adding the language used in the Rationale for Requirement R4, which says: “Sixty- full- calendar months, which begins on the effective date of the standard pursuant to the implementation plan…”

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

The Implementation Plan should address the possible scenario of a RAS misoperation occurring within 120 days of the Standard’s effective date, and if R5

would apply. Would this misoperation require the development of a CAP after the effective date of the Standard? This would apply for R6 and R7 as well.

For testing records will the RAS-owner need to have documentation of testing prior to the standard's effective date? This should be clarified in the Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer: No

Answer Comment: In the Implementation Plan, page 2, the following sentence has a grammatical/mechanical issue: “As of the date of posting of this Implementation Plan, however, the Commission has not issued an Final Order approving and retirement the Reliability Standards enumerated above.”

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: No

Answer Comment:

The Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be provided to allow for continued operation of those RAS, that are already in service when the standard becomes effective, after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

The Implementation Plan should be modified to include clarification for implementation of R4. Hydro One Networks Inc. agrees with the NPCC's TFSP in adding the language used in the Rationale box for R4, which says: "Sixty- full-calendar months, which begins on the effective date of the standard pursuant to the implementation plan…"

The standard or the Implementation Plan should allow the RAS-owner sufficient time to mitigate a design deficiency identified as part of R4, such as the lack of redundancy without removing the RAS from service. Clarification should be

provided to allow for continued operation of an existing RAS after a single component failure scenario is identified until a Corrective Action Plan can be completed.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: Yes

Answer Comment:

The Implementation Plan should specify when the first 5 year evaluation required by R4 should be completed for an existing RAS.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

We ask the SDT to clarify whether the approval process and the first technical evaluation needs to be performed before or after the effective date of the standard.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

7. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

We suggest that the standard have applicability to only the RAS entity, normally the primary Transmission Owner for the region affected. Including more than one party will make this standard too cumbersome and difficult to manage. The primary application of a RAS is to multi-facility, wide-area disturbances and as such is best vested in the Transmission Owner, who has a wider “system” viewpoint than the Generator Owner. We are concerned that Generator Owners may become inadvertent RAS-owners simply by owning a small fraction of the equipment needed for the RAS, and thus become subject to requirements R5 through R8, when they are typically passive parties to the RAS.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: na

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:
na

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter

Emily Rousseau

Segment

1,2,3,4,5,6

Entity

MRO

Region(s)

MRO

Selected Answer:

Answer Comment:

For R5, we propose revised wording that “within 120 days, or on a mutually agree upon schedule.” This would allow earlier or later completion of the analysis when warranted by unusual circumstances.

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

With regards to R5:

What is the benefit of providing the reviewing RC with results of a successful RAS operation?

With regards to R8:

Although functional testing would verify that the scheme is working as designed, there is no reason to believe that an RAS is any different from another protection system i.e., it would need to be tested at intervals outside the normal maintenance program. The testing of RAS should fall in line with PRC-005-3 requirements for monitored systems and unmonitored systems.

By requiring “at least once every six calendar years, each RAS- owner shall perform a functional test,” the drafting team is forcing all owners of a RAS that has any Protection Systems in it to abandon the PRC-005-3 12 year Maximum Maintenance Intervals allowed in tables 1-1, 1-2, 1-3, 1-5, and 4.

If Requirement R9 is adopted as stated in this draft of the standard, each segment of a RAS would have to be tested at a maximum interval of 6 calendar years. This would require, for example, that voltage and current sensing devices providing inputs to protective relays of a RAS “shall” be tested “at least once every six calendar years” instead of 12 Calendar years allowed in Table 1-3 of PRC-005-3.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer:

Answer Comment:

1. We ask for a clarification on the PRC-012-2 definition of RAS Owner to only “exclusively” include the owner of the scheme, and not include a “participating” entity in the RAS operation. The participating entity equipment would be covered by other standards such PRC-005-2 and thus should be excluded from standard.

2. The requirement R8 will require that the RAS is tested every 6 years, which is equivalent to any unmonitored relays that we have under PRC-005. However, testing the RAS may prove to be more laborious since it will most likely require coordination among multiple participating entities, so a more relaxed test sequence (12 years) would be preferred.

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter

Chris Scanlon

Segment

1

Entity

Exelon

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

RAS-entity should be responsible for R5 instead of RAS-owner. The RAS-entity, being designated to represent all RAS-owners, is in the best position to evaluate the operation of a RAS.

RAS-entity should be responsible for R8 functional testing.

R9 should include a sub-requirement for RCs to share their database with neighboring RCs to provide coordination of RAS schemes near RC borders.

Document Name:

Likes: 0

Dislikes: 0

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Eric Schwarzrock, Berkshire Hathaway - NV Energy, 5

Selected Answer:

Answer Comment:

There are numerous references to components of a RAS scheme in the standard and supplemental material, but there is no clear definition of what constitutes a component of a RAS scheme. A lack of a clear definition can lead to different interpretations of what a RAS component is. For example, Requirement R4.3 requires that "the possible inadvertent operation of the RAS resulting from any single RAS component malfunctions satisfies all of the following" conditions in 4.3.1 thru 4.3.5. While it is implied that the RAS components could include elements such as the RAS controller, communications, control circuitry, supervisory relays or functions (breaker 52A contact), and/or voltage or current sensing devices, it is not clearly stated. This leaves it open for some entities to possibly consider additional items such as a circuit breaker as a RAS component and other entities to not consider it. It could also allow some entities to take a more relaxed approach and exclude components that should possibly be included. A definition or explanation of RAS components should be added to the standard similar to the definitions used in PRC-005-4 (i.e. Automatic Reclosing and Sudden Pressure Relaying).

Document Name:

Likes: 0

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Currently as the standard is written, R5 and R6 require each RAS-owner to submit the results of the analysis and a CAP if needed. Tri-State does not believe it should be required that each RAS-owner submit the results and/or CAP rather than the RAS-entity. The RAS-entity can collect the results and submit 1 report/CAP, instead of several individual submittals from the seperate RAS-owners.

Also, Tri-State believes there is a numbering issue in Section II of Attachment 1 of the standard. It looks like "Documentation showing that the possible inadvertent operation of the RAS resulting from any singles RAS component malfunction satisfies all of the following:" should be #5 since it is a separate topic from #4.

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

a. The Rationale Box for R6 states that the “RAS-owner” will need to submit information in Attachment 1 to the RC, should this be the RAS-entity?

b. In R6, if the RAS-owner is the entity that performed the analysis in R4 of R5, when does the 6 month clock start (i.e., when was it notified)?

c. For R7, is the intent that each RAS-owner update the CAP with the RC? It seems like this should be the job of the RAS-entity, not multiple RAS-owners.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

As written the rationale for R8 is not incorporated into the requirement. R8 rationale states that correct operation of a RAS segment would qualify as a functional test. Please state that in the requirement so there is no confusion or debate if a correct operation resets the time frame necessary to perform a test.

SRP recommend the removal of the word “Requirement” in front of any R# designation. R1 stands for Requirement 1 and is sufficient. Saying "Requirement R1" is like saying Requirement Requirement 1. Also, the term “Requirement” is not a defined term.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Please refer to RSC-NPCC comments which Hydro-Quebec TransEnergie supports.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 1,10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Steve Edwards	Dominion	SERC	1
Joel Masters	SCE&G	SERC	1
David Greene	SERC staff	SERC	10
Jammie Lee	MEAG	SERC	1
Greg Davis	GTC	SERC	1

Voter Information

Voter

David Greene

Segment

1,10

Entity

SERC

Region(s)

SERC

Selected Answer:

Answer Comment:

If a RAS has multiple owners, and one or more owners is not compliant to R8, does this mean that all owners, or the RAS-entity, are non-compliant?

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

IMEA questions the need to include DP in the applicability. It is likely a DP will only own a part of a RAS. It should be adequate to specify TO coordination to verify RAS performance.

In R8, IMEA recommends deletion of "...and the proper operation of non-Protection System components."; i.e., it should be adequate to indicate only "...verify overall RAS performance."

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

- For R5, ATC proposes revising wording that “within 120 days, or on a mutually agree upon schedule.” This would allow earlier or later completion of the analysis when warranted by unusual circumstances.
- The purpose of Version 2 of PRC-005 was to consolidate all maintenance and testing of relays under one Standard. Having RAS testing within PRC-012-2 would be contrary to that end. ATC addresses this concern as follows:

Functional testing of RAS (as stated in Requirement 8 of PRC-012-2) is a maintenance and testing activity that would be better included in the PRC-005 standard. The present PRC-005-2 Reliability Standard is the maintenance standard that replaces PRC-005-1, 008, 011 and 017 and was designed to cover the maintenance of SPSs/RASs. However, Reliability Standard PRC-005-2 lacks intervals and activities related to non-protective devices such as programmable logic controllers. ATC recommends that a requirement for maintenance and testing of non-protective RAS components be added to a revision of PRC-005-2,

rather than be an outlying maintenance requirement located in the PRC-012-2 Standard.

Document Name:

Likes: 0

Dislikes: 0

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:

Answer Comment:

Regarding the rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS

is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clocks starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “B” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “B” had a nine year interval. The requirement should be modified to state that all segments shall be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

Peak was unable to locate the “consideration of comments” after the last round of comments posted on the NERC website. The “consideration of comments” are normally posted as part of the Standards Drafting Process to help commenters understand the SDT approach to comments made, and can affect subsequent comments submitted. Peak encourages NERC to post a “consideration of comments” from all comment periods.

In Attachment 2 under I: Design bullet 6, it states that the effects of future BES modifications… this seems to go outside of the scope of the operating horizon on which the RC is focused.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Kelly Dash On Behalf of: Robert Winston, Con Ed - Consolidated Edison Co. of New York, 3, 1, 5, 6

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

In the Rationale for Requirement R1, the last sentence of the first paragraph is “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? The term “functional modification” requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

“At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.”

Suggest revising to:

"At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

- An end to end test encompassing all components and testing actual functionality
- A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested"

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A" and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8, the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period and segment "B" is tested in year 1 (one year since its first test) and segment "A" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "A" had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

1. Regarding R1, it is not clear what the term “Functionally Modified” means. “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality” does not make sense. Does changing some overall scheme's functional logic without replacing any hardware device qualify as “Functional Modified”?

2. R2 should be changed to “Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1, shall, within four- full-calendar months of receipt, or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback including any identified reliability issues to the RAS- entity”.

3. R3 should be changed to “Following the review performed pursuant to Requirement R2 and receiving the feedback from the reviewing RC, the RAS-entity shall address each identified issue and obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS.

4. R5 requires RAS owner to analyze the performance of every RAS operations. It is not clear how much detail is required in this analysis. For those RAS schemes that operates routinely and regularly as designed, is a declaration of correct operation sufficient analysis?

5. R6 should be changed to “Within six- full- calendar months of identifying or being notified of a deficiency in its RAS pursuant to Requirement R4 or Requirement R5, each RAS- owner shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s)”.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team remove Generator Owners from the applicability section of the standard. Reclamation is unclear on how a Generator Owner could be considered to own all or part of a RAS. Reclamation does not believe that Generator Owners are well situated to analyze system-level RAS impacts or be considered a RAS-entity.

Reclamation believes that a list of elements that may constitute remedial action scheme elements would be helpful for understanding the scope of the standard. Project 2010-05.2, Phase 2 of Protection Systems, defines RAS by listing elements which do not individually constitute RAS. Reclamation is unclear on whether only protection system elements are intended to be considered part of a RAS, or whether elements affected by RAS operation like transmission lines or generators may also be considered RAS elements. Reclamation suggests the inclusion of a guidelines and technical basis section that better defines the parameters of RAS that must be analyzed under R4 and R6, and their relationship to system elements affected by RAS.

Reclamation also suggests that the RAS-entity should be responsible for the R5 analysis of each RAS operation or each failure of a RAS to operate. As written, the requirement would impose duplicative analysis requirements upon RAS owners that would not result in a corresponding reliability benefit. In addition, Reclamation believes that requiring each RAS-owner to conduct an analysis of each RAS operation is unwarranted because owners of one component of a RAS, such as a Generator Owner, would not be in the best position to analyze the RAS operation or its impact on the system. The RAS-entity is the RAS-owner designated to represent all RAS-owners for coordinating the review and approval of a RAS. As outlined in the Technical Justifications, “[t]he purpose of the RAS-entity is to be the single information conduit with each reviewing Reliability Coordinator (RC) for all RAS-owners for each RAS.” Reclamation believes the RAS analysis requirement should apply to the entity best situated to analyze the overall RAS operation, the RAS-entity.

Finally, Reclamation suggests that the RAS-entity should be responsible for the R8 functional test of each RAS that is required at least once every six calendar years. A RAS-owner responsible for limited RAS components would not be able to verify the overall RAS performance. The RAS-entity should be responsible for coordinating a functional test with all RAS-owners.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

1. Applicability Section:
    i. ReliabilityFirst believes the “RAS- entity” functional entity under the “Applicability” section may cause issues regarding which entity is responsible for requirements related to the “RAS-entity”. Absent any requirements requiring the RAS-owners to designate and make known the official RAS- entity, it may be difficult to assess compliance on the RAS-entity. ReliabilityFirst recommends including a new Requirement R1 as follows:
        a. R1. For each RAS that is owned by multiple RAS-owners, the RAS-owners shall designate one RAS- entity and inform the Reliability Coordinator(s) and Transmission Planner(s) that coordinates the area(s) where the RAS is located of such designation
2. Requirement R5
    i. As written, if there are multiple RAS-owners of a RAS, the expectation is to have multiple analyses performed. ReliabilityFirst believes it would be more appropriate to require the RAS-entity to perform one analysis with coordination of all associated RAS-owners.
3. Requirement R8
    i. Requirement R8 requires each RAS- owner to perform a functional test of each RAS. As written, in the case where multiple RAS-owners own a single RAS, multiple tests of the same RAS would be required to be run. ReliabilityFirst believes in cases where a RAS is owned by multiple RAS-owners, a single test should be required by the designated RAS-entity in conjunction with all the RAS-owners.
4. VSL for Requirement R4
    i. The time frames for the VSL for Requirement R4 are not all inclusive. For example, the Lower VSL states “less than 61-fullcalendar months” while the moderate VSL states “greater than 61- full- calendar months”. In this example it is unclear which VSL category an entity falls under if they perform the evaluation

in 61 months. Listed below is an example of the Lower VSL for the SDT's consideration.

a. The Transmission Planner performed the evaluation in accordance with Requirement R4, but in greater than 60- full- calendar months but less than **[or equal to]** 61- fullcalendar months.

5. VSL for Requirement R7

i. The Lower VSL states that if an entity failed both 7.2 and 7.3 they would fall under the Lower category. ReliabilityFirst questions what VSL an entity would fall under in the scenario where an entity is compliant with 7.2 but not 7.3?

- The RAS- owner implemented a CAP (Part 7.1), but failed to update the CAP (Part 7.2) if actions or timetables changed **[OR]** failed to notify one or more of the reviewing Reliability Coordinator(s) (Part 7.3), in accordance with Requirement R7.

Document Name:

Likes: 0

Dislikes: 0

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 -

Group Information

Group Name: IRC Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Matt Goldberg	ISONE	NPCC	2
Lori Spence	MISO	MRO	2
Christina Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter

Charles Yeung

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

Selected Answer:

Answer Comment:

Requirement R5: The SRC agrees that the RAS entity should evaluate RASs under the circumstances identified in Requirement R5, but would suggest that such entities be required to provide the results of such assessments to their Reliability Coordinator ***and Planning Coordinator***.

Requirement R9: In conjunction with the comment provided under Q2 to replace the TP with the PC, while the SRC agrees that the RC is the appropriate entity to maintain the database, it suggests that the Reliability Coordinator be required to share its database with the applicable Planning Coordinator(s) as some entities may have a need for planned RAS information for modeling and to ensure that appropriate information is shared across the long- and short-term horizons.

Document Name:

Likes:	1	Electric Reliability Council of Texas, Inc., 2, Axson Elizabeth
Dislikes:	0	

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy supports the SERC PCS comments on this standard.

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Eversource Energy - 3 -

Selected Answer:

Answer Comment:

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to: At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance

and the proper operation of non-Protection System components. This test can be either:

o An end to end test encompassing all components and testing actual functionality

o A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment "A", and a segment "B". Segment "A" is tested in year 1, segment "B" is tested in year 5. As per Requirement R8 the RAS has been tested within "six-calendar years." The clocks starts for the next functional test period, and segment "B" is tested in year 1 (one year since its first test), and segment "B" tested in year 5 (nine years since its first test). The RAS was tested within the "six-calendar years", but segment "B" had a nine year interval. Is this what is intended?

The RAS-owner should be included in Attachment 3.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. NPCC is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-005. NPCC suggests that all testing requirements for RAS should be contained in one standard.

NPCC suggests deletion of the phase "including any identified deficiencies" in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a "composite" RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Document Name:

Likes: 0

Dislikes: 0

Randi Heise - Dominion - Dominion Resources, Inc. - 5 -

Group Information

Group Name: Dominion - RCS

Group Member Name	Entity	Region	Segments
Larry Nash	Dominion Virginia Power	SERC	1
Louis Slade	Dominion Resources, Inc.	SERC	6
Connie Lowe	Dominion Resources, Inc.	RFC	3
Randi Heise	Dominion Resources, Inc,	NPCC	5

Voter Information

Voter

Randi Heise

Segment

5

Entity

Dominion - Dominion Resources, Inc.

Region(s)

Selected Answer:

Answer Comment:

Attachment 1, Section III-Implementation states, “5. Documentation describing the functional testing process.” Dominion recommends deleting this bullet. This information is not necessarily available during the preliminary design phase. The approval of the design is sought prior to detailed engineering. (Planning)

In R5 it states that the RAS owner analyzes the event, but in flow chart it states RAS owner and TP. Dominion suggests that the content in the Flow Chart be consistent with language of the Requirement.

R5 references the timeframe “within 120 calendar days”, however in other areas of the document the time frame is stated to be “within XX calendar months”. Dominion suggests updating the document to reflect the actual timeframe. Dominion also believes consistency is needed and suggests the timeframes reflect "full calendar months” versus “months”.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

NPCC,RFC

Selected Answer:

Answer Comment:

1. In addition to RAS-entity's, RAS-owners also have compliance obligations. Yet RAS-owners are not identified in any of the attachments. In addition, the RAS-related equipment of each owner should be identified in one attachment for use by the Reliability Coordinator, the Transmission Planner, and the Compliance Enforcement Authority. Expanding Attachment 3 may be the most efficient way to address these concerns.

2. R5 should be modified by changing this phrase: "…analyze the RAS performance…" to "analyze the performance of its RAS-related equipment." In cases where there are multiple RAS owners, a single RAS-owner cannot analyze the performance of the entire RAS; it can only analyze the performance of its own RAS-related equipment.

Document Name:

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes:	0	

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter

Richard Hoag

Segment

1,3,4,5,6

Entity

FirstEnergy - FirstEnergy Corporation

Region(s)

RFC

Selected Answer:

Answer Comment:

FirstEnergy would like additional clarification on the phrase “RAS controller” in the second paragraph of the Supplemental Material section in “Applicability”, 4.1.4 RAS-entity.

Additionally, FirstEnergy seeks to confirm that if a RAS system operates as planned/designed durnng normal operations then can the data from this actual operation be used to verify/satisfy testing requirements?

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-05.3 Submitted 10-5-15

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Jones	National Grid	NPCC	1

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

Because feeder loading can be changed intentionally, it is frequent to add, substitute, or remove load tripping devices (not distributed relays) in order to maintain the amount of load that is required by a load tripping RAS. Would these changes constitute a RAS functional modification? If so, suggest revising the definition of RAS functional modification. The Attachment 1 procedure that would have to be applied would be overly burdensome.

Regarding the Applicability Section 4.1.4 for the RAS-entity, who designates the RAS-owner to represent all RAS-owner(s)?

In the Rationale for Requirement R1, last sentence of the first paragraph, “A functional modification is any modification to a RAS beyond the replacement of components that preserves the original functionality.” How will “any modification to a RAS beyond the replacement of components” preserve the original

functionality? Functional modification requires clarification. Suggest developing a formal definition:

RAS Functional Modification--a change to the resultant action for which a RAS is designed.

Rationale for Requirement R8--We agree with segmented testing. However, the requirement does not state this and implies an overall test should still be performed.

R8 currently states:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components.

Suggest revising to:

At least once every six- calendar years, each RAS- owner shall perform a functional test of each RAS to verify the overall RAS performance and the proper operation of non-Protection System components. This test can be either:

- An end-to-end test encompassing all components and testing actual functionality

- A segmented test to test all the components by grouping them together into blocks until all parts of the RAS have been tested

Additional information in the Technical Guideline may be required to explain how the six year cycle is measured when allowing segmented testing. Segmented testing can test all components of an RAS every six years, but an individual component could end up being tested once every 10 years. For example, a RAS is designed so that it is comprised of a segment “A”, and a segment “B”. Segment “A” is tested in year 1, segment “B” is tested in year 5. As per Requirement R8 the RAS has been tested within “six-calendar years.” The clock starts for the next functional test period, and segment “B” is tested in year 1 (one year since its first test), and segment “A” tested in year 5 (nine years since its first test). The RAS was tested within the “six-calendar years”, but segment “A” had a nine year interval. Is this what is intended? It should be required that all segments be tested in the same calendar year.

The RAS-owner should be included in Attachment 3.

Requirement R8 and guidance provided in the supplemental material as written go beyond the direction stipulated by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a

RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. We are very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required by PRC-005. Suggest that all testing requirements for RAS should be contained in one standard. The testing time periods should be made consistent with Table 1-1 in PRC-005, specifically 6 years for an unmonitored protection system, and 12 years for an unmonitored microprocessor protection system.

NPCC suggests deletion of the phase “including any identified deficiencies” in R5 because Parts 5.1 through 5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

In C. Compliance, Section 1.2 Evidence Retention: the RC and TP have not been included. The TO, GO and DP are requested to keep data for requirements that they might not be responsible for.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6 -

Selected Answer:

Answer Comment:

Tacoma Power recommends that the definition of 'RAS-owner' be limited to functional ownership, as opposed to component ownership. For example, if one company owns a station DC supply, some wiring, and trip coil, but another company owns the control device at the same location, the entity that owns the control device should be a RAS-owner, and the entity that owns the station DC supply, wiring, and trip coil should not be a RAS-owner. Another example would be an entity that owns sensing devices that another entity uses to provide inputs to a relay or PLC that it owns; the entity that owns the sensing devices in this example should not be a RAS-owner. Yet another example is when one entity owns a portion of the communications system; simply owning part of the communications system should not make the entity a RAS-owner.

In the Q & A document, section 9, top of page 6, what if timing is only critical on the order of minutes (e.g., remediation of thermal overload). Could replacement of a T1 multiplexor possibly not be considered a RAS functional change in this case?

In the Q & A document, section 9, page 6, the example of "replacement of a failed RAS component with an identical component" seems overly exclusive. It is recommended to replace "identical" with "substantially identical."

In Requirement R6, why is "six-full calendar months," instead of simply "six calendar months," used?

In the Supplemental Material section, page 27, the following sentence has a grammatical/mechanical issue: "A RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service can do that only if that action is allowed for the Contingency for which it is designed."

In the Supplemental Material section, page 28, the following passage does not seem to read well: "These changes could result in inadvertent activation of that output, therefore, tripping too much load and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., "over trip") in order to satisfy single- component- failure requirements. System changes could result in too little load being tripped at affected locations and result in unacceptable BES performance if one of the loads failed to trip." Should the middle sentence be removed? It seems incongruous with the other two sentences.

In the Supplemental Material section, page 29, would a CAP be required if equipment fails that is readily replaceable/repairable? Tacoma Power maintains that CAP's should be required for issues that will require a longer time to address. In general, notification of RAS equipment failures is addressed by other standards.

In the Supplemental Material section, page 30, change "the , the" to "then, the."

Document Name:

Likes: 0

Dislikes: 0

Eric Olson - Transmission Agency of Northern California - 1 -

Selected Answer:

Answer Comment:

Although neither the Applicability section nor the Requirements of this draft standard distinguish between Protection System components and non-Protection System components of a RAS, the associated supporting information does make such a distinction. For example, the first paragraph of the Background Information section on the Unofficial Comment Form includes the following:

"The maintenance of the Protection System components associated with RAS (PRC-017-1 Remedial Action Scheme Maintenance and Testing) are already addressed in PRC-005. PRC-012-2 addresses the testing of the non-Protection System components associated with RAS/SPS."

NERC's supporting information elsewhere suggests that examples of non-Protection System components include programmable logic controllers, computers, and the control functions of microprocessor relays.

Based on TANC's understanding of NERC's intent for this standard, we suggest that NERC modify the definition of RAS-owner that is provided in the standard's Applicability section to the following.

*"RAS-owner - the Transmission Owner, Generator Owner, or Distribution Provider owns all or part of **the non-Protection System components of** a RAS" (bold text is added to current proposed definition).*

TANC's proposed modified definition would clarify that this standard and its requirements are not applicable to a Transmission Owner, Generator Owner, or Distribution Provider that doesn't own any non-Protection System components of a RAS.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Requirement R9: In conjunction with our comment under Q2 to replace TP with PC, while we agree that the RC is the appropriate entity to maintain the database, we suggest adding the Planning Coordinator to this requirement for RASs that have been planned and evaluated in the long-term planning timeframe. Some entities may have a need for planned RAS information for modeling.

We recommend that the standard should recognize that all RAS are not equal and therefore should not need the same level of design review (as per R1), performance requirement in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more "class" or "type" for RAS based on the impact of their misoperation or failure to operate on the system performance. Different class or type of RAS will then have different levels of design, performance and analysis requirements.

R8 and guidance provided in the supplemental material as written appears to overstep the direction provided by the SAR which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. The IESO is very concerned that there are different timeframes and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest

duplicative testing compared to testing already required in PRC-005. The IESO suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

The IESO suggests deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in will lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

The California ISO supports the comments of the ISO/RTO Standards Review Committee

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 3, Eddleman Tony

Dislikes: 0

Andrew Gallo - Austin Energy - 6 -

Selected Answer:

Answer Comment:

City of Austin dba Austin Energy suggests the SDT add clarifying language to R8 to account for a RAS-owner who owns only part of a RAS. In doing so, the SDT may need to consider how a partial RAS-owner will be able “to verify the overall RAS performance.”

Document Name:

Likes: 0

Dislikes: 0

Dixie Wells - Lower Colorado River Authority - 5 -

Group Information

Group Name: LCRA Compliance

Group Member Name	Entity	Region	Segments
Michael Shaw	LCRA	TRE	6
Teresa Cantwell	LCRA	TRE	1
Dixie Wells	LCRA	TRE	5

Voter Information

Voter

Dixie Wells

Segment

5

Entity

Lower Colorado River Authority

Region(s)

Selected Answer:

Answer Comment:

To address existing entity NERC registration in the ERCOT region, “Transmission Planner” should be replaced with “Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator.)”

R4. Each Transmission Planner (in the ERCOT Region this applies to the Planning Authority and /or Reliability Coordinator) shall perform an evaluation of each RAS within its planning area at least once every 60- full- calendar- months and provide the RAS- owner(s) and the reviewing Reliability Coordinator(s) the results including any identified deficiencies. Each evaluation shall determine whether: *[Violation Risk Factor: Medium] [Time Horizon: Long- term Planning]*

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8

and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

The second version of PRC-005 was intended to include all testing and maintenance requirements from PRC-017, and facilitate the retirement of PRC-017. Requirement 8 of the current draft of this standard (PRC-012-2) includes testing and maintenance requirements related to those found in PRC-017-0. Additionally, Requirement 8 of PRC-012-2 expands on those found in PRC-017-0 by including non-Protection System components. We feel this requirement should not be included in PRC-012-2, and we request a clear description of the differences of the intended purpose of the proposed PRC-012-2 Requirement 8 and that of PRC-017-0/PRC-005-2. Furthermore, the remaining requirements of PRC-012-2 seem to be primarily focused on system planning, and consideration should be given to moving these to the TPL standard family.

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE seeks clarification on the following:

- If a RAS is implemented to run-back a generator due to a line loading trigger level, is the Generator Owner a RAS-owner by default? Or is it dependent upon the ownership of the components that are used (e.g., protective or auxiliary relays, communication systems, sensing devices, station DC, control circuitry, etc.)?

- In Requirement R5, is the responsibility associated with the each RAS-owner correct? Should that responsibility be the RAS-entity (in collaboration with all RAS-owners) to avoid multiple analysis activities which may result in conflicting results and/or CAPs? If one RAS-owner

finds a deficiency in another owner's portion of the RAS, how is that notification made?

- In Requirement R5 there is no notification of a deficiency to a RAS-owner. Is notification considered to be when a RAS-owner recognizes a deficiency in its part of the RAS? R6 references a notification but it is not clear in R5.

- Does the SDT consider "arming", whether it signals another party to act or is used in situational awareness, as an integral part of RAS operation? Some RAS designs include an "arming" phase (e.g., A RAS will "arm" if the amperage on line X measure 900 amps. If the amperage measures 920 amps the RAS will activate. In some designs, "arming" may signal action to be taken by another party is needed (e.g. generator runback to level X), and if the action is not taken the RAS may fully activate (e.g. trip generator).) In the Supplemental Material (and somewhat, but not totally, mirrored in the rationale for R5) there is the statement: "A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiency(ies) that manifested in the incorrect RAS operation or failure of RAS to operate when expected." Failure of a RAS to arm, if designed to arm, is indicative that the design was improperly implemented.

- In Requirement R8, which entity responsible for coordinating the functional test for a multi-owner RAS that covers a wide area? The segmented approach referred to in the rationale may cover an individual RAS-owner's trip function or communications, but there needs to be an overall functional test of the logic that arms/disarms/activates the RAS, which may involve multiple RAS-owners. Texas RE recommends changing the requirement language to "RAS-owner, or RAS-entity as mutually agreed by the RAS-owners shall…". Also, a functional test should be required if there is a system change that affects one or more Elements that are monitored or operated as part of a RAS, in order to verify any logic changes. Requirements R1-R3 currently do not address functional testing, only the design. Texas RE recommends R8 indicate "proper operation of RAS" elements and not limit the functional test verification to non-Protection System components. Some Protection System components involved in the proper operation of a RAS may have an extended maintenance intervals and the RAS would not be functionally tested without including Protection System components. Overall RAS performance cannot be attained without functionally testing all aspects of the RAS.

Texas RE noticed an inconsistency between the requirement language and the RSAW. The requirement language of Requirement R5 states “Each RAS-owner shall” but the Note to Auditor in the Requirement R5 section of the RSAW indicates that a RAS-entity can provide the analysis. Registered entities are held accountable to the language of the requirement. Introducing the concept of a RAS-entity providing the information adds confusion. If the intent is for both the RAS-Owner and the RAS-entity to be able to analyze RAS performance and provide the results, Texas RE recommends changing the requirement language to “RAS-owner, or RAS-entity as mutually agreed by the RAS-owners analyze…”. Texas RE supports the idea of a RAS-entity doing the analysis.

Additionally, Texas RE recommends a requirement to report the degraded RAS to the RC. Texas RE noticed the referenced Standards/Requirements (i.e., Supplemental Material indicates PRC-001 R6 and TOP-001-2 R5) are either being retired or are not explicit enough to ensure that the reliability of the system is maintained for those who should have situational awareness. This is a perceived gap due to the current steady state of the standards.

Texas RE recommends Attachment 3 include the RAS-owner(s) as well as the RAS-entity. If Requirement R9 is left as “at a minimum”, that is all that will be done. Ownership is critical to know because of the responsibilities required in the majority of the Requirements (e.g., How will the TP provide results to owners without knowing all the owners?) The TP does not, generally, know the RAS-owners based on the ownership at the component level.

Document Name:

Likes: 0

Dislikes: 0

Dennis Chastain - Dennis Chastain On Behalf of: Brandy Spraker, Tennessee Valley Authority, 6, 1, 5, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

· Hydro One Networks Inc. recommends that the standard should recognize that all RASs are not equal and therefore, should not be subject to the same level of design review (as per R1), performance requirements in case of RAS failure (as per 4.4), and operation analysis (as per R5). We suggest defining two or more “class” or “type” for RAS based on the impact of their misoperation or failure to operate on the system performance. Different classes or types of RAS will consequently have different levels of design, performance and analysis requirements associated with them. Hydro One Networks Inc. would like to emphasize that in the absence of a means of differentiation (via typing or classes of RAS), utilities will feel compelled to spend significant capital, for little or no material improvement to system reliability.

· Hydro One Networks Inc. believes that requirement R8 and guidance provided in the supplemental material appear to overstep the direction provided by the SAR, which states that the standard will address maintenance and testing on non-Protection System components of a RAS. Maintenance of Protection Systems installed as a RAS for BES reliability is clearly covered in PRC-005. Hydro One Networks Inc. further joins the NPCC with its concern over the different timeframes provided and duplicative testing for RAS components. In particular, the supplemental material provided is very confusing and appears to suggest duplicative testing compared to testing already required in PRC-

005. Hydro One Networks Inc. agrees with the NPCC and suggests that all testing requirements for RAS should be contained in one standard. NERC PRC-005 applies to Protection Systems installed as Remedial Action Schemes for BES reliability. As such, all RAS Protective Relays, Communication Systems, Voltage and Current Sensing Devices Providing Inputs to Protective Relays, Control Circuitry, DC Supply, alarms and Automatic Reclosing Components are already included in PRC-005. Lastly, this requirement would force entities to perform testing on local area schemes; yet non-BES components are not subject to maintenance requirements under NERC PRC-005. Typing would be a good mythology to distinguish which RAS schemes should be subject to the strict maintenance requirements.

· Hydro One Networks Inc. also agrees with the NPCC in suggesting the deletion of the phase “including any identified deficiencies” in R5 because requirements R5.1 through R5.4 clearly define the necessary level of analysis required by the RAS-owner. Leaving this phrase in would lead to confusion over whether the proper operation of a “composite” RAS is considered a deficiency if one of the two redundant RAS suffer a component failure.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

The roles and relationships between the RAS-entity and the RAS-owners could be made clearer throughout the standard. Overall, FMPA supports the drafting team’s approach, but there have been several comments submitted that should be considered before the standard is approved and would like to see outreach done *before* the next posting of the standard for comment and ballot.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer:

Answer Comment:

(1) Requirement R9 requires the RC to update its RAS database annually. However, we believe the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency. If a RAS-owner has not made any changes to functionality and system conditions and operating configurations are as expected, we feel this requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria.

(2) We question how a RC is expected to maintain a dated revision history as evidence for Requirement R9 when the context of this requirement is to update a database. We believe the requirement is more of an administrative burden falling under Paragraph 81 Data Collection criteria, and the requirement should be rewritten to require the RC to develop and implement a process to conduct a review of its database and at what frequency.

(3) We believe the evidence retention of this standard should identify retention periods for applicable entities and not limit retention just for TOs, GOs, and DPs.

(4) The VSLs for Requirements R1 and R3 currently have only a Severe VSL identified. We believe the VSL criteria for these requirements could be written on a sliding time scale based on the projected installation or retirement dates of a RAS.

(5) We believe the VSL criteria listed with many requirements is too condensed. We recommend incrementing the criteria for Requirement R4 by quarters instead of by months. Moreover, we recommend incrementing the criteria for Requirement R5 by months rather than by every ten days. We also recommend incrementing the criteria for Requirements R8 and R9 by quarters rather every thirty days.

(6) We have concerns that the SDT has introduced a new measure of time, the "full-calendar-month." This measure will cause confusion with implementation and during audits. Moreover, there is inconsistent uses of this time measure within the standard. The SDT uses 60-full-calendar-months in R4, but does not use the same measurement in R5 for 120-calendar days and R8 for six-calendar years. Should R5 be four-full-calendar-months and R8 be six-full-calendar-years? The rationale for "full-calendar months" is only specified within the RSAW of this Standard. We feel the SDT should remove the measure of "full-calendar months" and replace it with "calendar months" to be consistent with the other NERC standards.

(7) We thank you for this opportunity to comment on this standard.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

BPA believes R5's reporting to the RC of the correct operation of a RAS is unduly onerous without providing value. BPA analyzes all RAS operations. If we see a scheme that operates too frequently (this is very subjective), we evaluate that scheme to see if there is something that can be done to minimize the number of operations. BPA proposes this be deleted from the requirement.

Document Name:

Likes: 0

Dislikes: 0