Consideration of Comments

Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings

The Project 2010-13.3 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from August 22, 2014 through October 6, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 53 sets of comments, including comments from approximately 147 different people from approximately 102 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of Changes to the Standard

The following is a summary of the change made to the proposed PRC-026-1 NERC Reliability Standard.

Applicability

Section 4.2, Facilities was revised from "The following Bulk Electric System Elements" to "The following Elements that are part of the Bulk Electric System (BES)" to clarify that the listed items are the items being addressed in the Requirements as the "Elements."

Requirement R1

The Elements from the Applicability 4.2 (i.e., generator, transformer, and transmission line BES Elements) was added for clarity. Also, the Requirement was modified to specifically require "notification" rather than "identify and provide notification." Identification of Elements based on the criteria is implied and necessary as a part of the Requirement.

Requirement R1, Criterion 1

The term "operating limit" was clarified to be "System Operating Limit (SOL)" to remove ambiguity between the operating and planning time frame. Also, "transmission switching station" was revised to

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

be “Transmission station.” The word “switching” did not add any additional clarity and the capitalized term “Transmission” references the *Glossary of Terms Used in NERC Reliability Standards*.

Requirement R1, Criterion 2

The phrase “constraints identified in system planning or operating studies” was modified to be “…a SOL identified by the Planning Coordinator’s methodology.” This allows the Standard to draw a connection between the FAC-010[2] NERC Reliability Standard applicable to the Planning Coordinator in the planning horizon.

Requirement R1, Criterion 3

This criterion originally identified Elements that formed the boundary of an island which in many cases would include Elements that were selected as arbitrary separation points and are not intended to be included within the scope of the Standard. Therefore, Criterion 3 was rewritten to reflect it is the Element which tripped on angular stability thus forming the island. Also, the criterion was updated to reflect the most recent “design assessment” by the Planning Coordinator (i.e., PRC-006) and when the Planning Coordinator uses angular stability as a design criteria for identifying islands.

Requirement R1, Criterion 4

The term “annual” was added to provide clarity.

Requirement R1, Criterion 5

Criterion 5 was removed from Requirement R1 because Requirements R2 and R3 in Draft 2 were eliminated. Those Requirements directed the Transmission Owner and Generator Owner to notify the Planning Coordinator of Elements that actually tripped due to a stable or unstable power swing. Criterion 5 created a loopback to the Generator Owner and Transmission Owner to ensure that load-responsive protective relays on identified Elements were evaluated on a periodic basis. Actual tripping events are now included in Requirement R2 (previously Requirement R4) and do not require periodic review, unless the Element trips due to a stable or unstable power swing.

Measure M1

Measure M1 was updated to reflect changes to Requirement R1 and to clarify that the focus is on notification and not identification of Elements.

Requirements R2 and R3

These Requirements were removed due to structural changes in Requirement R4 (now Requirement R2). The evaluation Requirement (now R2) was restructured to have two conditions for performance; 1) upon notification of an Element pursuant to Requirement R1, and 2) an actual event due to a stable or unstable power swing.

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[2] System Operating Limits Methodology for the Planning Horizon

Requirement R4

This Requirement became Requirement R2 due to the removal of Requirements R2 and R3. Most significantly, the Requirement was restructured to incorporate the removal of Requirements R2 and R3. It was determined that Elements that tripped due to a stable or unstable power swing (R2/R3) would be infrequent and more than likely a significantly large event which the Planning Coordinator would be aware of through an event analysis. The new structure of the Requirement causes an evaluation; however, it would not be necessary for the Planning Coordinator to be notified and then to continue notifying the Generator Owner and Transmission Owner. Elements that actually tripped due to stable or unstable power swings are not typical and requiring the Generator Owner and Transmission Owner to do a one-time analysis is sufficient to address the risk.

Requirements R5 and R6

These Requirements became Requirements R3 and R4 due to the removal of Requirements R2 and R3. Requirement R3 to develop the Corrective Action Plan (CAP) was inflexible as it only allowed the modification of a Protection System that did not meet the PRC-026-1 – Attachment B criteria. To correct this issue, Requirement R3 was modified to meet the purpose of the standard which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions. First, the Requirement was revised to include two conditions. The first condition requires a CAP to be developed such that the Protection System will meet the PRC-026-1 – Attachment B criteria. For example, this may include a Protection System modification or a system configuration change which causes the Protection System to meet the criteria. Second, the CAP allows power swing block to be applied such that the Protection System may be excluded from the Standard.

Also, the development period of the CAP was extended from 90 calendar days to six calendar months due to the complexities that might be involved with determining appropriate remediation of a Protection System that did not meet PRC-026-1 – Attachment B criteria.

Compliance Section

Section C1.1.2 was modified to conform evidence retention to the Reliability Assurance Initiative (RAI). Retention periods were set to 12 calendar months.

Violation Severity Levels

The Violation Severity Levels (VSL) were modified to align them with the revisions made to the Requirements.

PRC-026-1 – Attachments A and B

Attachment A received editorial changes and Attachment B, Criteria A was rewritten to clarify that a relay characteristic that is completely contained within the unstable power swing region meets the criteria. The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane.

Guidelines and Technical Basis

This section was revised substantively in response to comments and due to the removal of Requirements R2 and R3. Revisions are too numerous to list here effectively. Please see the Guidelines and Technical Basis redline document for changes.

Implementation Plan

The period for implementing the standard did not change substantively. Based on comments, the implementation time frame for Requirements R5 and R6 (now Requirements R3 and R4) were increased from 12 calendar months to 36 calendar months to align them with Requirement R4 (now Requirement R2).

1. Do you agree with the Applicability changes to PRC-026-1 (e.g., removal of the Reliability Coordinator and Transmission Planner)? If not, please explain why an entity is not appropriate and/or suggest an alternative that should identify the Elements according to the criteria.......... 17
2. Do you agree that the revisions to Requirement R1 improved clarity while remaining consistent with the focused approach of using the Criteria which came from recommendations in the PSRPS technical document (pg. 21 of 61)? If not, please explain why and provide an alternative, if any. 28
3. The previous Requirement R2 was split into Requirement R2 for the Transmission Owner and Requirement R3 for the Generator Owner in order to clarify the performance for identifying Elements that trip. Did this revision improve the understanding of what is required? If not, please explain why the Requirement(s) need additional clarification. 46
4. Requirement R4 (previously R3) contained multiple activities (e.g., demonstrate, develop a Corrective Action Plan, obtain agreement) and was ambiguous. Do you agree that the revision to Requirement R4 now provides a clearer understanding of what is required by the Generator Owner and Transmission Owner for an identified Element? Note: The Criterion is now found in PRC-026-1 – Attachment B, Criteria A and B. If not, please explain why the Requirement is not clear. 75
5. The new Requirement R5 (previously R4) and the new Requirement R6 address Corrective Action Plans (CAP), if any. Do you agree this is an improvement over having the development of the CAP comingled with other Requirement? If not, please explain. 87
6. Does the "Application Guidelines and Technical Basis" provide sufficient guidance, basis for approach, and examples to support performance of the requirements? If not, please provide specific detail that would improve the Guidelines and Technical Basis. 104
7. The Implementation Plan for the proposed standard has been revised, based on comments, to account for factors such as the initial influx of identified Elements and ongoing burden of entities to identify Elements and re-evaluate Protection Systems. Does the implementation plan provide sufficient time for implementing the standard? If not, please provide a justification for changing the proposed implementation period and for which Requirement. 119
8. If you have any other comments on PRC-026-1 that have not been stated above, please provide them here: 127

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group / Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilties Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
2.	Group	Janet Smith	Arizona Public Service Co	X		X		X	X				
N/A													
3.	Group	Eleanor Ewry	Puget Sound Energy	X		X		X					
N/A													
4.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
N/A													
5.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
6.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

				1	2	3	4	5	6	7	8	9	10
7.	Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Greg Campoli	ISO RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	Ben Li	IESO	NPCC	2
3.	Matt Goldberg	ISONE	NPCC	2
4.	Mark Holman	PJM	RFC	2
5.	Lori Spence	MISO	MRO	2
6.	Cheryl Moseley	ERCOT	ERCOT	2
7.	Ali Miremadi	CAISO	WECC	2

				1	2	3	4	5	6	7	8	9	10
9.	Group	Connie Lowe	Dominion	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Nash	Electric Transmission	SERC	1, 3
2.	Mike Garton	NERC Compliance Policy	NPCC	5, 6
3.	Louis Slade	NERC Compliance Policy	RFC	5, 6
4.	Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
5.	Christopher Mertz	Electric Transmission	SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
10.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Annette Bannon	PPL Generation, LLC	RFC	5
3.		PPL Susquehanna, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.			SPP	6
11.			WECC	6

				1	2	3	4	5	6	7	8	9	10
12.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Don Cuevas	Beaches Energy Services	FRCC	1
8.	Stanley Rzad	Keys Energy Services	FRCC	4
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steven Lancaster	Beaches Energy Services	FRCC	3
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Authority	FRCC	5

				1	2	3	4	5	6	7	8	9	10
13.	Group	Kathleen Black	DTE Electric Co.			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Dave Szulczewski	DE-EE Relay Eng Supv	RFC	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Richard Hoag	FirstEnergy Corp.	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Wiliam Smith	First Energy Corp	RFC	1
2.	Cindy Stewart	FirstEnergycorp.com	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6
6.	Richard Hoag	First Energy Corp	RFC	NA

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6
2.	Rene Free	Santee Cooper	SERC	1, 3, 5, 6
3.	Bridget Coffman	Santee Cooper	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Jamison Cawley	Nebraska Power Review Board	SPP	1, 3, 5
3.	Michael Jacobs	Camstex	NA - Not Applicable	NA
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Derek Brown	Westar Energy	SPP	1, 3, 5, 6
8.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
9.	Charles Lee	Kansas City Power & Light	SPP	1, 3, 5, 6
10.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
11.	James Nail	City of Independence, MO	SPP	3, 5
12.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
13.	Jonathan Hayes	Southwest Power Pool	SPP	2
14.	Robert Rhodes	Southwest Power Pool	SPP	2
15.	Shannon Mickens	Southwest Power Pool	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative	WECC	1
4.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
5.	Kevin Lyons	Central Iowa Power Cooperative	MRO	1
6.	Ellen Watkins	Sunflower Electric Power Cooperative	SPP	1
7.	Ginger Mercier	Prairie Power	SERC	3
8.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
9.	Paul Jackson	Buckeye Power	RFC	3, 4, 5

				1	2	3	4	5	6	7	8	9	10
20.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1
2.	Dean Bender	System Control Engineering	WECC	1
3.	Chuck Matthews	Transmission Planning	WECC	1
4.	Jim Gronquist	Transmission Planning	WECC	1

				1	2	3	4	5	6	7	8	9	10
21.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
22.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
23.	Individual	Oliver Burke	Entergy Services, Inc.	X									
24.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
25.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
26.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
27.	Individual	Mark Wilson	Independent Electricity System Operator		X								
28.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
29.	Individual	Alshare Hughes	Luminant Generation Company, LLC					X	X	X			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	Barbara Kedrowski	Wisconsin Electric			X	X	X					
31.	Individual	Bill Fowler	City of Tallahassee			X							
32.	Individual	Jonathan Meyer	Idaho Power	X									
33.	Individual	John Pearson/Matt Goldberg	ISO New England		X								
34.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
35.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
36.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
37.	Individual	Glenn Pressler	CPS Energy	X		X		X					
38.	Individual	Jamison Cawley	Nebraska Public Power District (NPPD)	X		X		X					
39.	Individual	John Merrell	Tacoma Power	X									
40.	Individual	David Jendras	Ameren	X		X		X	X				
41.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
42.	Individual	Michael Moltane	ITC	X									
43.	Individual	Karin Schweitzer	Texas Reliability Entity										X
44.	Individual	Muhammed Ali	Hydro One	X		X							
45.	Individual	Ayesha Sabouba	Hydro One	X		X							
46.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
47.	Individual	Dixie Wells	Lower Colorado River Authority					X					
48.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
49.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
50.	Individual	John Brockhan	CenterPoint Energy	X									
51.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
52.	Individual	Kurt LaFrance	Consumers Energy Company			X	X	X					
53.	Individual	Richard Vine	California ISO		X								

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates entities that support the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the standard drafting team. This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be. Please see the responses to the entity’s comments that are being supported here.

Organization	Agree	Supporting Comments of “Entity Name”
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI agrees with SPP Commments **Response:** The standard drafting team thanks you for participating, please see the responses to SPP Standard Review Group.

1. **Do you agree with the Applicability changes to PRC-026-1 (e.g., removal of the Reliability Coordinator and Transmission Planner)? If not, please explain why an entity is not appropriate and/or suggest an alternative that should identify the Elements according to the criteria.**

Summary Consideration: About 87 percent of commenters agree with the Applicability change in Requirement R1 of the Standard to remove the Reliability Coordinator and Transmission Planner. The following summary discusses the major concerns that resulted in revisions to the Standard and one minor concern that did not result in a change to the Standard.

There were three significant themes of comments that resulted in a revision to the Standard.

First, there were five comments supported by 35 individuals (includes Questions 1-8) that were concerned that an applicable Generator Owner or Transmission Owner would be exempted from the proposed PRC-026-1 Standard if the entity applies out-step-blocking. The standard drafting team agrees and when entities implement power swing blocking (PSB) relays, do so using engineering judgment and accepted industry practices, the reliability purpose of the Standard is met. Draft 3, Requirement R3 (previously Draft 2, Requirement R5) for developing a Corrective Action Plan (CAP) clarifies this as an option to meeting the Purpose Statement of the Standard.

Second, two comments represented by 11 individuals raised questions about the use of “operating” in conjunction with the “planning” time horizon in the Requirement R1 criteria. The standard drafting team revised Requirement R1, Criterion 1 that is applicable to the Planning Coordinator to replace the phrase “an operating limit” with “System Operating Limit (SOL).” Further, the standard drafting team reworded Requirement R1, Criterion 2 to remove the phrase “identified in system planning or operating studies” and clarify that the SOL is identified based on the Planning Coordinator’s methodology in the “planning” horizon. This revision aligns the *Glossary of Terms Used in NERC Reliability Standards* defined term, “System Operating Limit” or “SOL” with its use in the Standard. Also, this revision aligns the use of “SOL” with the Planning Coordinator’s methodology of how SOLs are developed according to the NERC Reliability Standard, FAC-10 (i.e., System Operating Limits Methodology for the Planning Horizon).

Last, there were two comments supported by five individuals that commented about the overlap between the proposed PRC-026-1, Requirements R2 and R3 and NERC Reliability Standard PRC-004.[3] The concern stemmed from the perception of having to perform Protection System reviews in both standards. The standard drafting team addressed this concern by removing Requirements R2 and R3 (notification to the Planning Coordinator) and incorporating a revision to the Draft 3, Requirement R2 (previously Draft 2,

[3] Protection System Misoperation Identification and Correction.

Requirement R4). The revision clarified that the Generator Owner and Transmission Owner must perform an evaluation of its load-responsive protective relays according to the Requirement upon becoming aware of a stable or unstable power swing.

The following summarizes a comment that did not result in a change to the Standard. Two comments supported by nine individuals did not want the Transmission Planner removed from the applicability of the Standard. The standard drafting team removed the Transmission Planner (and Reliability Coordinator) as applicable entities in the last draft (Draft 2) of the proposed standard in response to comments to address concerns about overlap and potential gaps when identifying Elements in Requirement R1 according to the criteria. Although the PSRPS Report[4] suggested the Transmission Planner and Reliability Coordinator entities along with the Planning Coordinator for inclusion in the Standard's Applicability, the standard drafting team agreed with comments received on Draft 1 that the Planning Coordinator is in the best position to identify Elements to avoid duplication and potential gaps.

Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency	No	FMPA is comfortable with the removal of the Reliability Coordinator and Transmission Planner, subject to comments we are making on R2, R3 and in response to question 8. **Response:** Please see comments in Question 8.
Santee Cooper	No	There seems to be some overlap between PRC-004 and R2 and R3 of this standard (PRC-026). For compliance with PRC-004, entities have to analyze all operations in order to prove that all misoperations are identified. To identify an Element that (according to R2 and R3 of PRC-026) "trips due to a stable or unstable power swing during an actual system Disturbance due to the operation of its load-responsive protective relays," a similar proof could be required, that all trips of load responsive

[4] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 1 Comment
		relays were evaluated under a criteria to rule out operation due to stable or unstable power swings. The listed Rationale for R2 gives mention to the review of relay tripping is addressed in other NERC Reliability Standards, so there seems to be a nod given to PRC-004, but it should be clearer as to the interrelationship between these standards. Significant confusion could result if the interrelationship or dividing line (whichever is more appropriate) between these two standards is defined further. Will compliance with R2 and R3 of PRC-026 only involve having the data for the operations determined to be caused by power swings, or will it require data that entities provide documentation of the evaluation each operation for power swing implications? **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading “Becoming Aware of an Element That Tripped in Response to a Power Swing” on how an entity would “become aware.” Changes made.
ISO New England	No	While we agree with the removal of the Reliability Coordinator and Transmission Planner, we don’t believe that entities should be exempted from the standard by the linkage to Attachment A. Attachment A excludes Relay elements supervised by power

Organization	Yes or No	Question 1 Comment
		swing blocking. An entity could just install Out of Step Blocking equipment with nothing to ensure that it is set correctly and the standard would not apply through the exclusion in Attachment A. **Response:** The standard drafting team contends that the installation of power swing blocking relays is an effective means to prevent tripping for stable power swings. The drafting team contends that entities that implement power swing blocking (PSB) relays would do so using engineering judgment and accepted industry practices. A discussion of PSB is in the Application Guidelines. No change made.
Texas Reliability Entity	No	Texas Reliability Entity, Inc. (Texas RE) has concerns regarding the removal of the Reliability Coordinator (RC) from the applicability, particularly for Criteria 1 and 2 of R1. The time horizons that the Planning Coordinator (PC) and RC evaluate are different, with the Planning horizon being > 1 year and the Operations horizon being real-time to < 1 year. When the SDT removed the RC from the applicability, the Operations Planning time horizon was also removed; however, there is still language within Criteria 1 and 2 of R1 addressing angular stability constraints as monitored as part of a System Operating Limit identified in operating studies. Operating studies are not typically conducted by the PC but are conducted by the RC. Based on the language in the Criteria, it is unclear to Texas RE whether the intent of the standard is to only identify elements at risk in the Long-term Planning horizon or to identify elements at risk in both the Operations horizon and the Long-term Planning horizon. Texas RE requests clarification on this issue from the SDT. Please also see our comments to Questions 2 and 3 regarding time horizon concerns. **Response:** The standard drafting team revised Requirement R1, Criterion 1 to replace the phrase “an operating limit” with “System Operating Limit (SOL).” Further, the standard drafting team reworded Requirement R1, Criterion 2 to remove the phrase “identified in system planning or operating studies” and clarify that the SOL is identified based on the Planning Coordinator’s methodology in the planning horizon.

Organization	Yes or No	Question 1 Comment
		This revision aligns use of the term in the standard with the *Glossary of Terms Used in NERC Reliability Standards* defined term, "System Operating Limit" or "SOL." Also, this revision aligns the use of "SOL" with the Planning Coordinator's methodology of how SOLs are developed according to FAC-10 (System Operating Limits Methodology for the Planning Horizon). Change made.
Consumers Energy Company	No	The Transmission Owner and Generator Owner on their own do not have the capability to determine if a trip was caused due to a swing. In most cases the Generator Owner has no knowledge of events on the transmission system, and in many cases the Transmission Owner may only own one terminal of a transmission line. Given the available data for a single terminal, there is no reliable way for an Owner to determine if a trip was due to a fault or a swing. The Transmission Planner and/or Reliability Coordinator have the broad system perspective to track how a swing moves through the transmission system and impacts each element and should determine whether any given event was involved a swing through a specific Element. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element

Organization	Yes or No	Question 1 Comment
		That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made.
California ISO	No	The California ISO does not agree with the change to remove the Transmission Planner in the Applicability section and in Requirement R1. The California ISO supports continuing to include the Transmission Planner in Requirement R1 as suggested by the PSRPS Report. **Response:** The standard drafting team removed the Reliability Coordinator and Transmission Planner as applicable entities in Draft 2 of the proposed standard in response to comments to address concerns about overlap and potential gaps when identifying Elements in Requirement R1. Although the PSRPS Report[5] suggested entities for applicability, the standard drafting team agreed with comments received on Draft 1 and that the Planning Coordinator is in the best position to identify Elements to avoid duplication and potential gaps. No change made.
Northeast Power Coordinating Council	Yes	
Arizona Public Service Co	Yes	
Puget Sound Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company;	Yes	Simplifying the requirement to a single entity clarified the responsibilities. **Response:** The standard drafting team thanks you for your comment.

[5] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 1 Comment
Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Colorado Springs Utilities	Yes	No Comments
Duke Energy	Yes	
ISO RTO Council Standards Review Committee	Yes	The Standards Review Committee (SRC) agrees with the removal of the Reliability Coordinator and Transmission Planner; however, there remains concern that that entities could be exempted from the standard by the linkage to Attachment A as it excludes Relay elements supervised by power swing blocking. The SRC, therefore, recommends that the SDT assure all Applicability is explicit in the Applicability Section of the standard and that exemptions or other criteria are not embedded in Attachment A. (note CAISO does not support the response to Question 1) **Response:** The standard drafting team contends that the installation of power swing blocking relays is an effective means to prevent tripping for stable power swings. The drafting team contends that entities that implement power swing blocking (PSB) relays would do so using engineering judgment and accepted industry practices. A discussion of PSB is in the Application Guidelines. No change made.
Dominion	Yes	
JEA	Yes	
DTE Electric Co.	Yes	

Organization	Yes or No	Question 1 Comment
FirstEnergy Corp.	Yes	
Tennessee Valley Authority	Yes	
SPP Standards Review Group	Yes	Thank you for removing the Reliability Coordinator function. The Reliability Coordinator has no place in this standard. **Response:** The standard drafting team thanks you for your comment.
ACES Standards Collaborators	Yes	(1) We largely agree with the applicability changes. We thank the drafting team for removing Transmission Planner and avoiding the confusion that has occurred in so many other standards from joint responsibility to meet the same requirements as the PC. **Response:** The standard drafting team thanks you for your comment. (2) We are concerned with the removal of the RC. Per the SDT's response to our comments regarding which SOLs (planning horizon is covered FAC-010 and operating horizon is covered in FAC-011), the SDT indicated that they intended for both to apply. Since the SOL methodology that applies in the operating time horizon is written by the RC, the PC may not be familiar enough with the RC's methodology to determine which operating horizon SOLs are due to angular stability. Wouldn't it be easier for the RC to notify the PC of those operating SOLs caused by angular stability? **Response:** The standard drafting team revised Requirement R1, Criterion 1 to replace the phrase "an operating limit" with "System Operating Limit (SOL)." Further, the standard drafting team reworded Requirement R1, Criterion 2 to remove the phrase "identified in system planning or operating studies" and clarify that the SOL is identified based on the Planning Coordinator's methodology in the planning horizon. This revision aligns use of the term in the standard with the *Glossary of Terms Used in NERC Reliability Standards* defined term, "System Operating Limit" or "SOL." Also, this revision aligns the use of "SOL" with the Planning Coordinator's methodology of how

Organization	Yes or No	Question 1 Comment
		SOLs are developed according to FAC-10 (System Operating Limits Methodology for the Planning Horizon). Change made.
Bonneville Power Administration	Yes	
Oncor Electric Delivery LLC	Yes	
Public Service Enterprise Group	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Generation Company, LLC	Yes	
Wisconsin Electric	Yes	
City of Tallahassee	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc.	Yes	
CPS Energy	Yes	
Nebraska Public Power District (NPPD)	Yes	
Tacoma Power	Yes	
Ameren	Yes	
ITC	Yes	
Hydro One	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
Lower Colorado River Authority	Yes	
Georgia Transmission Corporation	Yes	
CenterPoint Energy	Yes	

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
PPL NERC Registered Affiliates		These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. **Response:** The standard drafting team thanks you for your comment.

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

Summary Consideration: Two-thirds of commenters agreed that the revisions improved clarity while remaining consistent with the focused approach of using the Requirement R1 criteria which is supported by the recommendation in the PSRPS Report[6] (pg. 21 of 61). The following summary discusses the most significant concerns that resulted in a revision to the Standard and one minor concern that did not result in a change to the Standard.

There were only three significant themes of comments that resulted in a revision to the Standard. First, two comments supported by 13 individuals requested that Requirement R1 be split into two Requirements, one for identifying BES Elements and one for notifying the Generator Owner and Transmission Owner. The drafting team did not agree and alternatively modified Requirement R1 to place the performance on notification of the Element(s) based on the criteria. Notifying the Generator Owner and Transmission any Elements that meet the criteria infers that the identification is being performed in order to determine what BES Elements must be provided in a notification, if any. Second, two comments each from an individual requested clarity between the lowercase phrase "operating limit" and the NERC defined term, "System Operating Limit" or SOL. The standard drafting team revised the Standard to use "SOL" exclusively for clarity since the methodology for determining of SOLs is addressed by the NERC Reliability Standard FAC-010.[7] Third, only one comment provided minor editorial corrections to the Standard which the standard drafting team implemented.

The following summarizes comment themes that did not result in a change to the Standard. First, nine comments supported by 46 individuals (including Questions 1-8) commented that the Standard is going beyond the intent of the Federal Energy Regulatory Commission (FERC) Order No. 733. The standard drafting team responded that it is important to note that this Standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Therefore, the Standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to either a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirements R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the Standard, and not require that entities assess Protection System performance during unstable swings.

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[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] System Operating Limits Methodology for the Planning Horizon

The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused approach is based on the PSRPS Report, recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude "unstable" power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to "unstable" power swings provides a reliability benefit.

Second, eight comments supported by 32 individuals noted that the entities are not persuaded that a Standard is needed, primarily because of the PSRPS Report. The standard drafting team addressed entity concerns about not pursuing a standard in the previous posting of the Consideration of Comments to Draft 1.[8]

Third, six comments represented by 36 individuals submitted general questions and comments about the Standard, which did not result in a revision based on the comments. For example, why is the Planning Coordinator required to notify the Generator Owner and Transmission Owner each calendar year of the BES Element(s) that tripped based on Requirement R1, Criterion 3 concerning underfrequency load shedding (UFLS).[9] Since Draft 3, Requirement R2 has a re-evaluation component driven by the BES Element notification by the Planning Coordinator and a point in time of the last evaluation, the standard drafting team concluded that not including additional language for varying assessments done by the Planning Coordinator reduces complexity and does not result in a significant burden. Another comment questioned why the Standard required the Generator Owner and Transmission Owner to notify the Planning Coordinator. The reason was to create a loopback for the re-evaluation; however, the standard drafting team based on other comments later removed Requirement R1, Criterion 5 and Requirements R2 and R3 due to determining a better way to address actual events due to stable or unstable power swings. One comment wanted additional work to align the Standard with TPL-001-4 and another to add back in the Transmission Planner to the Standard's Applicability.

Fourth, four comments supported by 17 individuals (including Questions 1-8) wanted the Standard to provide a Requirement for the exchange of information (e.g., system impedance data); however, the standard drafting team concluded that a Requirement for the information exchange would be administrative and have limited reliability benefit for activities that entities are already performing.

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[8] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

[9] NERC Reliability Standard PRC-006-1 – *Automatic Underfrequency Load Shedding* has a five year periodicity.

Last, two comments represented by 32 individuals suggested rewording Requirement R1 to include the phrase "…for all design criteria events…" The standard drafting team agreed that the suggestion did not add clarity to Requirement R1.

Organization	Yes or No	Question 2 Comment
Colorado Springs Utilities	No	We agree with the Public Service Electric and Gas Company comments. **Response:** The standard drafting team thanks you for participating, please see the responses to Public Service Enterprise Group. Additional Comments: 1.) Please define a "transmission switching station," is that the same thing as a sub-station? **Response:** The standard drafting team revised the phrase "transmission switching station" to be "Transmission station" to refer to the *Glossary of Terms Used in NERC Reliability Standards*. Change made. 2.) Please clarify "angular" stability limit versus just a stability limit. **Response:** The descriptor "angular" was added in Draft 2 to clarify that the "stability limit" pertains to an angular stability limit and not a voltage stability limit, for example. No change made. 3.) How are people modeling the relay settings for R1.4? Our facility ratings take into account relay setting limitations and the facility ratings are used in the models. Is that sufficient modeling or is there some specific modeling expected for R1.4? **Response:** The standard drafting team notes that Requirement R1, Criterion 4 provides a mechanism for the Planning Coordinator to identify Element in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance. As discussed in the Guidelines and Technical Basis, the soon-to-be enforceable TPL-001-4 Reliability Standard calls for the use generic or actual relay models. It will be through a Planning Coordinator's compliance with TPL-001-4 that Elements will be identified where relay tripping occurs

Organization	Yes or No	Question 2 Comment
		due to a stable or unstable power swing during a simulated disturbance. PRC-026-1 does not require modeling of relays in planning studies. No change made.
PPL NERC Registered Affiliates	No	The process of PCs annually performing an analysis and notifying TO/GOs of applicable Elements per R1, and of TO/GOs then evaluating these Elements per R4, should be clarified to note that where relays meeting criteria 1-3 of R1 are on the PC's list year after year a new evaluation is not required each time unless conditions have materially changed (threshold TBD by the SDT). **Response:** The standard drafting team intends that the Planning Coordinator will notify the respective Generator Owner and Transmission Owners annually and that Elements will, from time to time, be added or removed accordingly. In doing so, Requirement R1 supports the re-evaluation in Requirement R4 (now Requirement R2) every five (previously three) calendar years should the Element remain on the list.
SPP Standards Review Group	No	In light of the fact that the purpose of this standard is "To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions" which is in agreement with the FERC Order 733 (Section 150 of the FERC Order: "requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement"), it is an unnecessary extension of the Order to include unstable power swings. The Standard Drafting Team stated "The phase "stable or unstable" was inserted to clarify that both are applicable to power swings because the goal of the standard is to identify Elements susceptible to either" overreaches the FERC Order. We recommend that the term 'Unstable Power Swing' be removed from the standard. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order

Organization	Yes or No	Question 2 Comment
		No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirements R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused approach is based on the PSRPS Report,[10] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made.
Seattle City Light	No	Seattle City Light is not convinced that this Standard is warranted, and does not find comfort in the tortured process associated with developing the recommendations of the PSRPS document. The changes, as far as they go, do add some clarity to R1. **Response:** The standard drafting team thanks you for your comment.
ACES Standards Collaborators	No	(1) We agree that the clarity of Requirement R1 is improved but we still have a couple of concerns.

[10] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20 Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 2 Comment
		Response: The standard drafting team thanks you for your comment. (2) Why is the PC required to notify the GO and TO of Elements that were involved in actual events when the GO and TO are the entities that notify the PC in the first place? Doesn't the PC just need to notify the GO and TO when those Elements are no longer susceptible to tripping from stable power swings? **Response:** The standard drafting team included Criterion 5 in Requirement R1 as a mechanism to (1) create awareness for the Planning Coordinator that has wide-area awareness; and (2) to close the loop back to the Generator Owner or Transmission Owner to continue to re-evaluate its load-responsive protective relays associated with the identified Element; and (3) should the electric system topology change where the Element is no longer susceptible to a power swing as determined by the Planning Coordinator, the Element is no longer required to be identified pursuant to Requirement R1. However, the standard drafting team has revised the standard such that Requirement R1, Criterion 5 has been eliminated, along with Requirements R2 and R3. (3) In Criterion 4, why are unstable power swings included? Elements should trip due to unstable power swings. Why does the GO and TO need to modify relaying for unstable power swings? **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard.

Organization	Yes or No	Question 2 Comment
		The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused approach is based on the PSRPS Report,[11] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made. Since PRC-006 only requires the PC to simulate the UFLS Program every five years, it seems that requiring the PC to identify the same Elements that form a UFLS island boundary every year is unnecessary. Criterion 3 should be modified to clarify that this notification is only necessary once every five years when the UFLS study is completed. **Response:** The standard drafting team contends that the Planning Coordinator must notify the Generator Owner and Transmission Owner of the identified Elements annually, even if the specified criteria in Requirement R1 is performed less frequently. The periodicity is reasonable and practical to ensure timely notification of identified Elements to the Generator Owner and Transmission Owner. No change made. The standard drafting team provided additional dialogue about this in the Guidelines and Technical Basis under the heading "Requirement R1." Change made.

[11] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20 Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group	No	The Planning Coordinator should be obligated in R1 to provide system impedance data as described in the Attachment B Criteria for each Element identified in R1 to the TO or GO that owns the Element. PCs maintain the models that contain this data, and having them provide it will result in consistency for relays set within the PC's area. **Response:** The standard drafting team contends that Generator Owners and Transmission Owners already obtain this information periodically for other purposes and for performance under other NERC Reliability Standards. No change made.
Xcel Energy	No	Criteria 1 uses the term "operating limit" and Criteria 2 uses the term "System Operating Limit;" although both are identified by the existence of angular stability constraints, thus seemingly defining the same type of operating constraint, i.e. operating limit. Xcel Energy would suggest either explaining the difference between the terms "operating limit" and "System Operating Limit", or eliminating the potentially duplicative criterion, since a "Generator" can be an "Element". **Response:** The standard drafting team replaced the term "operating limit" with "System Operating Limit (SOL)" in Criterion 1 to be consistent with Criterion 2. Criterion 1 identifies generators and Elements terminating at the Transmission station associated with the generator(s), while Criterion 2 identifies transmission Elements that are monitored as part of an SOL. Change made. In our opinion, Requirement R1 is organized and written in a manner that makes interpretation difficult. Xcel Energy suggests that the drafting team consider re-organizing this requirement as suggested below. R1 could be split so that R1 requires the PC to perform the following at least once per year; R1.1 would require the PC to identify Elements meeting the bulleted list of criteria; R1.2 would require notification to the respective Generator Owner and Transmission owner of each Element identified in R1.1.

Organization	Yes or No	Question 2 Comment
		Regardless of whether this Requirement R1 is re-organized as suggested above or not, we suggest the following rewrite of of Criteria 1 to minimize ambiguity. Criteria 1 can be split either at the "or" (as in "...addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements...") or at the "and" (as in "...addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements..."). To provide additional clarity, Criteria 1 could be rewritten as: "Generator(s) and Elements Terminating at associated transmission stations where angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS)." These potential modifications would improve the readability of the requirement and provide for easier alignment with the associated Measures and VSLs. **Response:** The standard drafting team thanks you for providing suggestions to improve clarity; however, the standard drafting team declines to implement the suggestion to avoid a loss in the intended purpose. No change made. In addition, M1 could be rephrased to state "Each Planning Coordinator shall have dated evidence that demonstrates identification of Elements meeting the R1 criteria was performed on a calendar year basis and dated evidence that demonstrates the respective owners of the identified Elements were notified on a calendar year basis". **Response:** The standard drafting team declines to make the modification since Requirement R1 was not modified according to the previous comment. The existing M1 phrasing of "identification and respective notification of the Elements" reads as if the Elements are being notified rather than the owners of the Elements. **Response:** The standard drafting team made an editorial revision to Measure M1 to address the issue raised in the comment. Change made.

Organization	Yes or No	Question 2 Comment
Luminant Generation Company, LLC	No	Requirement R1 provides additional clarity of which Elements (including transformers, generators) are included in a notification by the Transmission Planner. In light of the fact that the purpose of this standard is “To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions” which is in agreement with the FERC Order 733 (Section 150 of the FERC Order: “requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement”), it is an unnecessary extension of the Order to include unstable power swings. The Standard Drafting Team stated “The phase “stable or unstable” was inserted to clarify that both are applicable to power swings because the goal of the standard is to identify Elements susceptible to either” overreaches the FERC Order. Luminant recommends that unstable power swings be removed. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard’s focused approach is based on the PSRPS Report,[12]

[12] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20 Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 2 Comment
		recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made. Additionally, R1 should be modified so that notifications are not required for elements and relays that were previously identified and are currently in a Corrective Action Plan. **Response:** The standard drafting team contends that providing additional caveats and stipulations in the requirements does not provide a reliability benefit and only complicates the clarity and intent of the Requirements. No change made. The Planning Assessment referenced in R1, Criteria 4 should be limited to the contingencies in TPL-001-0.1 "Table 1 Transmission System Standards - Normal and Emergency Conditions" Category A, B, C and D to focus the power swing evaluations and corrective action development on activities that support the reliability of the BES. **Response:** The standard drafting team contends that the proposed standard is in alignment with the TPL-001-4 Reliability Standard, which becomes effective on January 1, 2015. Furthermore, the contingencies to which the Planning Coordinator will consider have not been specified in the Requirement R1 criteria because there is no certainty to what system conditions may produce a stable or unstable power swing on a particular Element within the study. The criterion do not require the Planning Coordinator to specifically evaluate for a power swing, only identify the Element if observed as tripping during a simulated Disturbance. No change made.
City of Tallahassee	No	The Planning Coordinator should be obligated in R1 to provide system impedance data as described in the Attachment B Criteria for each Element identified in R1 to the TO

Organization	Yes or No	Question 2 Comment
		or GO that owns the Element. PCs maintain the models that contain this data, and having them provide it will result in consistency for relays set within the PC's area. **Response:** The standard drafting team contends that Generator Owners and Transmission Owners already obtain this information periodically for other purposes and for performance under other NERC Reliability Standards. No change made.
ISO New England	No	R1 should be changed to read: R1. Each Planning Coordinator shall, for all design criteria events at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any: **Response:** The standard drafting team contends that the provided suggestion "…for all design criteria events…" does not add clarity to Requirement R1. No change made.
Kansas City Power & Light	No	A yearly notification is too often for this requirement since this information will rarely change. We suggest a yearly notification for any change from the previous year, with a five year notification of all identified Elements. **Response:** The standard drafting team contends that the Planning Coordinator must notify the Generator Owner and Transmission Owner of the identified Elements annually, even if the specified criteria in Requirement R1 is performed less frequently. The periodicity is reasonable and practical to ensure timely notification of identified Elements to the Generator Owner and Transmission Owner. No change made.
CPS Energy	No	In general, support Luminant comments. **Response:** The standard drafting team thanks you for your comment.
Nebraska Public Power District (NPPD)	No	The PSRPS Recommendations Section states that the SPCS determined a Reliability Standard is not needed.

Organization	Yes or No	Question 2 Comment
		Response: The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[13] in the introductory remarks regarding the need for a standard to meet regulatory directives.
Georgia Transmission Corporation	No	Recommend further clarity and a revision to R1 criteria 1 such as: From this: Generator(s) where an angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s). To this: Generator(s) and those interconnecting Elements terminating at the transmission switching station associated with the generator(s), where an angular stability constraint exists that is addressed by an operating limit or a Remedial Action Scheme (RAS). **Response:** The standard drafting team thanks you for providing suggestions to improve clarity; however, the standard drafting team declines to implement the suggestion to avoid a loss in the intended purpose. No change made.
California ISO	No	The California ISO does not agree with the change to remove the Transmission Planner in the Applicability section and in Requirement R1. The California ISO supports continuing to include the Transmission Planner in Requirement R1 as suggested by the PSRPS Report. **Response:** The standard drafting team removed the Reliability Coordinator and Transmission Planning as applicable entities in Draft 2 of the proposed standard in response to comments to address concerns about overlap and potential gaps when

[13] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Yes or No	Question 2 Comment
		identifying Elements in Requirement R1. Although the v suggested entities for applicability, the standard drafting team agreed with comments on Draft 2 and that the Planning Coordinator is in the best position to identify Elements to avoid duplication and potential gaps. No change made.
Northeast Power Coordinating Council	Yes	Comments regarding requirement R1 can be found in the response to Question 8. Additionally, suggest clarifying requirement R1 by adding the wording “for all design criteria events” so as to make it read: R1. Each Planning Coordinator shall, for all design criteria events, at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any: **Response:** The standard drafting team contends that the provided suggestion “…for all design criteria events…” does not add clarity to Requirement R1. No change made.
Arizona Public Service Co	Yes	
Puget Sound Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Simplifying the requirement to a single entity clarified the responsibilities. **Response:** The standard drafting team thanks you for your comment.

Organization	Yes or No	Question 2 Comment
Duke Energy	Yes	
ISO RTO Council Standards Review Committee	Yes	The SRC agrees that the revisions improved the clarity of Requirement R1. However, to ensure consistency with the other requirements within the Standard, the SDT recommends that Requirement R1 also be broken into two (2) requirements, one addressing identification and one addressing notification. **Response:** The standard drafting team revised Requirement R1 to focus on the notification of Elements to the Generator Owner and Transmission Owner that meet one or more of the criteria, not on the identification of the Elements which are identified by other studies. Change made. Additionally, Requirement R1 should be changed to read: R1. Each Planning Coordinator shall, for all design criteria events at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any: **Response:** The standard drafting team contends that the provided suggestion "…for all design criteria events…" does not add clarity to Requirement R1. No change made. Finally, the SRC recommends the following revision to Criterion 1 of Requirement R1 to streamline and ensure that the focus remains on Remedial Action Schemes: 1. Generator(s) where an angular stability constraint exists that is addressed by a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s). **Response:** The standard drafting team thanks you for providing suggestions to improve clarity; however, the standard drafting team declines to implement the suggestion to avoid a loss in the intended purpose. No change made.
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	Yes	
DTE Electric Co.	Yes	
FirstEnergy Corp.	Yes	FirstEnergy suggests a slight modification to the wording of R1 Criteria 5 for clarity, as follows: “An Element reported by the Transmission Owner pursuant to Requirement R2 or Generator Owner pursuant to R3, unless ...”. **Response:** The standard drafting team has revised the standard such that Requirement R1, Criterion 5 has been eliminated, along with Requirements R2 and R3.
Tennessee Valley Authority	Yes	The addition of criteria 5 seems circular in that the PC is notifying the GO or TO about Elements they already know about. If the PC’s analysis applying criteria 1-4 does not identify these Elements initially, why should the same PC criteria be entrusted to determine that “the Element is no longer susceptible to power swings”? **Response:** The standard drafting team has revised the standard such that Requirement R1, Criterion 5 has been eliminated, along with Requirements R2 and R3.
Bonneville Power Administration	Yes	BPA requests a revision to R1 to separate **customer notifications** from **technical analysis**. R1.1 Each Planning Coordinator shall, at least once each calendar year, identify each Element in its area that meets one or more of the following criteria R1.2 Each Planning Coordinator shall provide notification to each respective Generator Owner or Transmission Owner that owns an Element identified in R1.1. **Response:** The standard drafting team revised Requirement R1 to focus on the notification of Elements to the Generator Owner and Transmission Owner that meet one or more of the criteria, not on the identification of the Elements which are identified by other studies. Change made.

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery LLC	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Wisconsin Electric	Yes	
Idaho Power	Yes	
Pepco Holdings Inc.	Yes	
Tacoma Power	Yes	
Ameren	Yes	
ITC	Yes	
Texas Reliability Entity	Yes	While Texas RE agrees with the approach of using criteria from the PSRPS technical document, we have concerns about the stated time horizon. Requirement R1 Criterion 2 states that the PC should include elements identified in operating studies, but the time horizon for this requirement is Long-term Planning. Texas RE suggests that either the Operations Planning time horizon needs to be added to this requirement or the reference to operating studies needs to be removed, whichever is in line with the intent of the SDT. **Response:** The standard drafting team revised Requirement R1, Criterion 1 to replace the phrase “an operating limit” with “System Operating Limit (SOL).” Further, the

Organization	Yes or No	Question 2 Comment
		standard drafting team reworded Requirement R1, Criterion 2 to remove the phrase "identified in system planning or operating studies" and clarify that the SOL is identified based on the Planning Coordinator's methodology in the planning horizon. This revision aligns use of the term in the standard with the *Glossary of Terms Used in NERC Reliability Standards* defined term, "System Operating Limit" or "SOL." Also, this revision aligns the use of "SOL" with the Planning Coordinator's methodology of how SOLs are developed according to FAC-10 (System Operating Limits Methodology for the Planning Horizon). Change made.
Manitoba Hydro	Yes	
Lower Colorado River Authority	Yes	
American Transmission Company, LLC	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Consumers Energy Company	Yes	
Arizona Public Service	Yes	

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

Summary Consideration: Almost two-thirds of entities providing comment agree that Requirements R2 and R3 provided clarity over the previous Draft 2. Below is a summary of the comments received about the two Requirements that required the Transmission Owner (Requirement R2) and the Generator Owner (Requirement R3) to provide notification of any BES Element that tripped due to a stable or unstable power swing.

There were two significant themes of comments that resulted in a revision to the Standard. First, fifteen comments supported by 55 individuals expressed concerns about a number of issues regarding Requirements R2 and R3. These concerns included, but are not limited to: 1) the 30 day notification time frame by the Generator Owner and Transmission Owner to the Planning Coordinator was too short; 2) the Measures (M2 and M3) focused on identification of the BES Elements whereas the Requirements only addressed notification; 3) additional detail about BES Elements that form a boundary of an island; 4) the ability to "identify a stable or unstable power swing;" 5) the review of a Protection System within PRC-026-1 and potential conflicts or overlaps with NERC Reliability Standard PRC-004[14] that addresses identification of Misoperations of Protection Systems; 6) how is the starting point established for the purpose of measuring performance of the Requirement; 7) inconsistency with the Violation Severity Levels (VSL); and 8) more information needed on how to identify powers swings.

To address these concerns, the standard drafting team removed the previous Requirements R2 (Transmission Owner) and R3 (Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element that tripped due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Draft 3, Requirement R2 (previously Draft 2, Requirement R4) for load-responsive relays to be evaluated under two conditions:

- Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or
- Becoming aware of an Element that tripped in response to a stable or unstable power swing.

The standard drafting team provided supporting detail on the second bullet (above) in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware."

[14] Protection System Misoperation Identification and Correction.

Second, six comments supported by 19 individuals commented that the Standard should not require the Generator Owner and Transmission Owners to identify “unstable” power swings. Comments stemmed from concerns over the ability to identify (e.g., needing digital fault recording), overstepping the Federal Energy Regulatory Commission (FERC) Order No. 733 directive to address only stable, and that the Standard seems to require that entities track every BES Element trip to prove that the entity reviewed it for stable and unstable power swing. To address this concern, the standard drafting team removed Requirements R2 and R3 and incorporated a change to Requirement R2 (previously R4) for when an entity “becomes aware” of a stable or unstable power swing that tripped its BES Element. Performance is required when the entity “becomes aware” of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

The following summarizes comments did not result in a change to the Standard. First, two comments each from an individual concerned that the Standard is limiting an entity’s ability to trip for “unstable” power swings. The Draft 3, Requirement R2 (previously Draft 2, Requirement R4) ensures that the Protection System will be evaluated after tripping for an “unstable” power swing to ensure that the Protection System is expected to not trip for a “stable” power swing. The Protection System is not precluded from tripping in response to an unstable power swing. The standard drafting team contends that any out-of-step tripping requirements would be identified independent of this standard and, if required, would need to remain in service.

Last, an individual commented that the Standard should exclude trips during black-starting and system restoration. The standard drafting team disagreed because trips that occur during these circumstances should be evaluated to ensure that load-responsive protective relays are expected to not trip in response to a stable power swing during non-Fault conditions.

Organization	Yes or No	Question 3 Comment
Puget Sound Energy	No	In general, we agree with the comments submitted by PSEG. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity’s implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction - see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval.

Organization	Yes or No	Question 3 Comment
		In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., “correct operations.” We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase “system Disturbance” has same meaning as the NERC Glossary term for “Disturbance.” In other words, “system” is unnecessary. In addition, a “Fault” was stated to be a “Disturbance.” Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. o If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner’s compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only “make work” for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 - Event Reporting - see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-

Organization	Yes or No	Question 3 Comment
		2.pdf. For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: o Automatic firm load shedding on p. 9 o Loss of firm load (preferably limited to non-weather related load loss) on p. 10 o System separation (islanding) on p.10 o Generation loss on p.10, o Complete loss of off-site power to a nuclear plant on p. 10, and o Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing. Without this notification, Events that happen outside of the Planning Coordinator's PC Area may not be properly identified by the affected PC. If this is not the intent of the standard, there needs to be a distinction made between whether relays should be evaluated against local disturbances (disturbances within the PC Area) and system-wide disturbances that would be communicated throughout the region. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions:

Organization	Yes or No	Question 3 Comment
		Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made. The standard drafting team made revisions to the standard which eliminated the term "Disturbance" as defined by the *Glossary of Terms Used in NERC Reliability Standards*.
Colorado Springs Utilities	No	We agree with the Public Service Electric and Gas Company comments. **Response:** The standard drafting team thanks you for participating, please see the responses to Public Service Enterprise Group.
ISO RTO Council Standards Review Committee	No	The SRC notes that Requirements R2 and R3 are about notification if an element meeting specified criteria is identified. However, the measures are primarily focused on identification. Accordingly, the measures should be revised for consistency with the associated Requirements R2 and R3. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the conflict is no longer present. Change made.
Dominion	No	M3 seems to be missing the word 'meet'; suggest M3 read as; M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which 'meet' the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Organization	Yes or No	Question 3 Comment
		Response: The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made. Dominion agrees with the split of R2, however, elements could have their load-responsive protective relays operate prior to the formation of an island. In the Application Guide, a section should be included to better define methods used for boundary detection, if we are required to determine if the element was in-fact the boundary to an island. Otherwise, power swings could cause relays to operate without internal detection algorithms picking up the swing. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made.
Florida Municipal Power Agency	No	Requirements R2 and R3 need further clarification. FMPA agrees that splitting the Requirement was beneficial. However, FMPA finds the following issues left requiring resolution, which point to the need to better coordinate this standard with PRC-004: 1. The language is crafted as if a typical TO or GO would easily be able to determine that an element tripped due to a power swing. This only makes sense for large vertically integrated utilities in which staff with a variety of knowledge bases and skill sets may be working together. In reality, for smaller utilities that may be only a TO/DP or GO, this determination will require some involvement from a TP, PC, TOP, or RC, with staff that have a) access to real time information, event records, and other information beyond what any single TO or GO may have and b) an understanding of the expected regional stability performance which TO/GO staff may not have. Realistically it should only be presumed the TO or GO staff will be able to conclude that their relays did not trip for a fault. **Response:** The standard drafting team contends that PRC-026-1 does not require an entity to determine whether an Element tripped due to a power swing. This is accomplished in the revision to Requirement R2 (previously Requirement R4) that when an entity “becomes aware” it would evaluate the relay(s). The identification of a power swing that causes a BES Element trip could be determined through an entity’s

Organization	Yes or No	Question 3 Comment
		Protection System analysis process (e.g., PRC-004[15]), event analysis review by the entity, region, or NERC. 2. The standard sets a 30 day clock which starts with a piece of information that isn't required or driven from anywhere - namely, the point in time at which at TO or GO discovers that any relay operated (either correctly or incorrectly) due to a power swing. Since there is currently no place where it is required that correct/proper relay operation be documented, it is not clear what sort of documentation the TO/GO will have and what process, performed by what staff, would drive the TO/GO to "initially discover" that the relay operated due to a power swing. The point being- in a normal PRC-004 investigation, at such time as it is discovered that a relay properly operated, there is no requirement for any formal report, on any formal schedule, to include that information. At what point does the "official" starting point of this 30 day clock occur? This points to the need for further/better coordination with PRC-004. **Response:** The standard drafting team removed Requirements R2 and R3 and notes it is up to the entity to determine when it becomes aware of the condition upon which performance is measured. Change made.
Seminole Electric Cooperative, Inc.	No	Requirements R2 and R3 appear to require the reporting of trips due to UNSTABLE power swings. Seminole feels that a better mechanism for collecting information on unstable power swings is through NERC Section 1600 data requests, not via a Standard. Requirements R2 and R3 utilize the term "identifying." Can the SDT add language in the application guidelines that clarifies that "identifying" means "making a determination," as the term identifying is somewhat unclear to Seminole. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator in, Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised

[15] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 3 Comment
		Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading “Becoming Aware of an Element That Tripped in Response to a Power Swing” on how an entity would “become aware.” Changes made.
Xcel Energy	No	The Measures M2 & M3 do not match the R2 & R3 requirements. The measures only require that the TO and GO have evidence of the identification of elements, but do not require evidence of notification of identified Elements to the PC. The VSLs for R2 & R3 classify it as a Severe VSL if the TO or GO fails to identify an Element in accordance with R2 & R3. However, the way R2 & R3 are written, there is no requirement for the TO or GO to identify anything. As the requirements are currently written, the only requirement is that the PC is notified within 30 calendar days of identification of an Element meeting the criteria. If a TO or GO does not identify an Element, they can never be in violation of R2 or R3 as written. Further, if there is no requirement for identification of Elements meeting R2 or R3 criteria, it is not clear what the starting point is for determining the 30 day notification period. How is the official date of identification of an Element pursuant to R2 & R3 determined? And how is it officially documented for use in establishing PC notification due date in determining the severity of the violation? It is unclear what action the PC is going to take, upon notification of the identification of an Element meeting R2 & R3 criteria, beyond adding the Element to the R1 list for future years that will be provided to the TO and GO. If that is the only resulting action,

Organization	Yes or No	Question 3 Comment
		the 30 day notification of the PC or the <10 day overdue Lower VSL, <20 day overdue Moderate VSL, <30 day overdue High VSL or >30 day overdue Severe VSL do not seem to align. R4 directs the TO and GO to analyze the Elements within 12 calendar months of identifying the Element pursuant to R2 or R3. If the only action taken by the PC is to add the Element to the R1 list for future years, is would seem to be just as effective from a reliability perspective to give the TO and GO up to the next calendar year to notify the PC about R2 7 R3 identified elements and to align the R2 & R3 VSL notification timeframes with those allowed for the PC to TO/GO notifications in R1. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings, thus eliminating the connection with PRC-004.[16] In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made. The standard drafting team has revised the standard such that Requirement R1, Criterion 5 has been eliminated, along with Requirements R2 and R3. Change made.

[16] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 3 Comment
		The standard drafting team removed Requirements R2 and R3 and notes it is up to the entity to determine when it becomes aware of the condition upon which performance is measured. Change made.
Wisconsin Electric	No	: We take issue with this requirement. First, it will be difficult or impossible for the Generator Owner (GO) to comply with. The requirement in R3 is to notify the Planning Coordinator of an Element that trips due to a stable or unstable power swing during an actual system Disturbance due to the operation of its load-responsive protective relays. Without dynamic disturbance recording (DDR), it may not be possible to determine that the relay tripped due to a power swing. The GO is not required to have (DDR) capability for every generator. Note that DDR will only be required by the future PRC-002 standard for a subset of generators, not all of them. The most that a GO may be able to do is to say that a generator relay may have operated for a power swing, especially when the Generator Owner does not own or operate the connected transmission system. **Response:** The standard drafting team contends that PRC-026-1 does not require an entity to determine whether an Element tripped due to a power swing. This is accomplished in the revision to Requirement R2 (previously Requirement R4) that when an entity "becomes aware" it would evaluate the relay(s). The identification of a power swing that causes a BES Element trip could be determined through an entity's Protection System analysis process (e.g., PRC-004[17]), event analysis review by the entity, region, or NERC. The standard drafting team removed Requirements R2 and R3 and notes it is up to the entity to determine when it becomes aware of the condition upon which performance is measured. Change made. Second, if an unstable power swing passes through the generator or generator step-up transformer, the generator SHOULD trip in order to prevent or limit possible damage.

[17] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 3 Comment
		The generator out-of-step relay is used for this purpose, and it does not appear that this standard will allow the necessary settings on the Device 78 element to properly protect the generator. Common industry settings for the 78 out-of-step function do not appear to be possible based on the Application Guidelines in the draft standard. For these reasons, we believe that this requirement should be removed. If it is retained, then the scope of the applicability to generators should be limited to those generators where DDR will be required per the future PRC-002. **Response:** Requirement R2 (previously R4) ensures that the Protection System will be evaluated after tripping for an unstable power swing to ensure that the Protection System is expected to not trip for a stable power swing. The Protection System is not precluded from tripping in response to an unstable power swing. The standard drafting team contends that any out-of-step tripping requirements would be identified independent of this standard and, if required, would need to remain in service. Examples have been added to the Guidelines and Technical Basis to illustrate an entity complying with the standard while using out-of-step trip relaying.
City of Tallahassee	No	R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity's implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction - see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve

Organization	Yes or No	Question 3 Comment
		reliability.PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., “correct operations.” We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase “system Disturbance” has same meaning as the NERC Glossary term for “Disturbance.” In other words, “system” is unnecessary. In addition, a “Fault” was stated to be a “Disturbance.” Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. o If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner’s compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only “make work” for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 - Event Reporting - see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf. For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: o Automatic firm load shedding on p. 9 o Loss of firm load (preferably limited to non-weather related load loss) on p. 10 o System separation (islanding) on p.10

Organization	Yes or No	Question 3 Comment
		o Generation loss on p.10, o Complete loss of off-site power to a nuclear plant on p. 10, and o Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made. The standard drafting team made revisions to the standard which eliminated the term "Disturbance" as defined by the *Glossary of Terms Used in NERC Reliability Standards*.
ISO New England	No	Although splitting the requirement into two adds clarity, what was the underlying uncertainty that this is intended to address? R4 continues to be a combined TO/GO

Organization	Yes or No	Question 3 Comment
		requirement that was not split. We ask whether the same uncertainty exists for R4 (previously R3) and should it also be split? **Response:** The standard drafting team notes that the previous splitting of the Draft 1 Requirement into the Draft 2, Requirements R2 and R3 was intended for clarifying that the "islanding" criteria was only related to the Transmission Owner. The evaluation of load-responsive protective relays under the new Requirement R2 (previously Requirement R4) applies to both the Generator Owner and Transmission Owner in evaluating the 120 degree separation angle.
Kansas City Power & Light	No	A trip during a stable power swing is a mis-operation and is covered in PRC-004. A trip during an unstable power swing is an intended result and not applicable to this standard. We suggest removing these two requirements. **Response:** The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made. This Requirement ensures that the Protection System will be evaluated after tripping for an unstable power swing to ensure that the Protection System is expected to not trip for a stable power swing. The Protection System is not precluded from tripping in response to an unstable power swing.
Pepco Holdings Inc.	No	The 30 day time line provided for Requirement R2 in the standard to determine if an element operated due to either of the Criteria provided seems aggressive. The shortest amount of time we have to determine if a protective relaying scheme mis-operated under current quarterly reporting requirements for PRC-004 is 60 days. It would make sense if the timeline for this standard was adjusted to match. In addition, the requirement as written does not seem to differentiate if this level of analysis is required for the operation of all in-scope protective relaying schemes or just those that were determined to mis-operated. Requiring this level of study for all in-

Organization	Yes or No	Question 3 Comment
		scope protective relaying schemes would seem to provide a tremendous compliance burden to the Transmission Owners. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made.
CPS Energy	No	In general, support PSEG comments. **Response:** The standard drafting team thanks you for participating, please see the responses to Public Service Enterprise Group.
Nebraska Public Power District (NPPD)	No	Both R2 and R3 requirements appear to take a "wait and see" approach rather than a proactive approach. This doesn't seem practical when maintaining the reliable operation of the BES. We recommend elimination of both R2 and R3.Additionally, R2 states that the TO would need to identify "an Element that forms the boundary of an island during an actual system Disturbance due to the operation of its load-responsive protective relays." This type of event would be very complex and would likely include many contingencies. Thus the statement seems too general and all-encompassing. We feel this reliability function might be better served by the Planning Coordinator(s) or

Organization	Yes or No	Question 3 Comment
		Reliability Entity facilitating an event analysis where better decisions and recommendations can be made, given their wide-area view and awareness of reliability issues. If a relay did trip on OOS for a stable power swing, the likelihood of it being part of a larger event or a misoperation is high. If it were a misoperation, it would then be addressed in another standard or event analysis process. As noted above it seems R2 and R3 are better served by existing processes or standards. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading “Becoming Aware of an Element That Tripped in Response to a Power Swing” on how an entity would “become aware.” Changes made.
Ameren	No	Ameren adopts the following comment submitted by PSEG. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity’s implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and

Organization	Yes or No	Question 3 Comment
		Correction - see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., “correct operations.” We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase “system Disturbance” has same meaning as the NERC Glossary term for “Disturbance.” In other words, “system” is unnecessary. In addition, a “Fault” was stated to be a “Disturbance.” Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. o If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner’s compliance with PRC-004-3. Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only “make work” for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be

Organization	Yes or No	Question 3 Comment
		reduced to a subset of events that are reported to NERC under EOP-004-2 - Event Reporting - see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf. For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: o Automatic firm load shedding on p. 9 o Loss of firm load (preferably limited to non-weather related load loss) on p. 10 o System separation (islanding) on p.10 o Generation loss on p.10, o Complete loss of off-site power to a nuclear plant on p. 10, and o Transmission loss on p.11. To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing.

Organization	Yes or No	Question 3 Comment
		The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading “Becoming Aware of an Element That Tripped in Response to a Power Swing” on how an entity would “become aware.” Changes made. The standard drafting team made revisions to the standard which eliminated the term “Disturbance” as defined by the *Glossary of Terms Used in NERC Reliability Standards*.
CenterPoint Energy	No	CenterPoint Energy recommends additional clarification be provided for identifying and the reporting, or not reporting, of Elements that trip from power swings during system disturbances. We believe certain tripping should be excluded, such as, when reconnecting islands and during black start restoration. We suggest the following sentence be added to Requirement R1, Criterion 1: “Notification shall not be provided if an Element trips from a power swing that occurs during operator-initiated switching to reconnect islands, to restore load during Black Start activities, or to synchronize a generating unit to the system”. In addition, it may be needed to clarify that tripping of Elements from voltage or frequency oscillations due to power system stabilizer issues are not to be reported. **Response:** The standard drafting team has revised Requirement R4 (now Requirement R2) to require the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays applied at the terminals of an Element that trips upon “becoming aware of an Element that tripped in response to a stable or unstable power swing.” The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis on how an entity would “become aware.” The standard drafting team concluded exclusions for system restoration or black-starting should not be provided because it could be detrimental to reliability. Any Element that tripped in response to a stable or unstable power swing must be addressed, especially involving restoration and black-starting because those are conditions where power swings would be expected and it is critical that load-responsive protective relays are secure for stable power swings.

Organization	Yes or No	Question 3 Comment
Consumers Energy Company	No	R2 and R3 require modification to provide clarity in how the Owner will determine if any given trip is due to a swing. Without specific guidance on how to identify and document when a swing occurs and whether that swing caused a trip, we do not believe we are able to comply with R2 or R3. For instance, if an Owner only has electromechanical relays on a terminal, and does not own the other terminal(s) of that element, how is it to determine the impedance trajectory and whether or not that trajectory was a swing or a fault? **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made.
Northeast Power Coordinating Council	Yes	Comments regarding requirements R2 and R3 can be found in the response to Question 8. **Response:** The standard drafting team thanks you for your comment, please see response in Question 8. Splitting requirement R2 into two requirements adds clarity.

Organization	Yes or No	Question 3 Comment
		Response: The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made.
Arizona Public Service Co	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Since the criteria is not completely the same for the TO and GO, spliting the previous R2 into a new R2 and new R3 was a good move. **Response:** The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made.
Duke Energy	Yes	
JEA	Yes	
DTE Electric Co.	Yes	
FirstEnergy Corp.	Yes	Regarding R3, as a Generator Owner in a deregulated / competitive environment, we still have a concern about being held accountable for events for which we are unaware - power swings or Disturbances on the system (Criteria 1) - due to FERC Code of Conduct separation with the regulated system. We are not aware of system events. We realize, however, that R3 says, "... within 30 calendar days of identifying ..."; the concern simply

Organization	Yes or No	Question 3 Comment
		relates to the level of responsibility placed on the GO to "identify" tripping of load-responsive relays caused by "... a stable or unstable power swing during an actual system Disturbance ...". **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made.
Tennessee Valley Authority	Yes	
Seattle City Light	Yes	
ACES Standards Collaborators	Yes	(1) We agree with splitting the requirements because the GO simply is not privy to the same information as the TO to identify island boundaries. However, it is reasonable for the GO to work with the TO and TOP to determine the cause of the relay operations to be from a stable power swing.

Organization	Yes or No	Question 3 Comment
		Response: The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made. (2) We believe the time horizons for both requirements R2 and R3 need to be modified. Both are currently long-term planning which is one year or longer into the future. Since this is an evaluation of actual events, we believe the Operations Assessment time horizon is more accurate. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made. (3) Why is tripping from unstable power swings included in these two requirements? Relays should trip due to unstable power swings. The FERC directive compelled NERC to develop a standard that requires protection systems to be able to differentiate between stable power swings and faults. The directive did not require NERC to specifically address unstable powers swings. We recommend removing unstable power swings from both R2 and R3. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and

Organization	Yes or No	Question 3 Comment
		faults. This standard's focused approach is based on the PSRPS Report,[18] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made.
Bonneville Power Administration	Yes	
Oncor Electric Delivery LLC	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Luminant Generation Company, LLC	Yes	
Idaho Power	Yes	

[18] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 3 Comment
Tacoma Power	Yes	
ITC	Yes	
Texas Reliability Entity	Yes	While Texas RE agrees with splitting the previous Requirement R2 into Requirement R2 for the Transmission Owner (TO) and Requirement R3 for the Generator Owner (GO) for clarity, we have concerns regarding the stated time horizon. Requirement R2 states that the TO shall notify the PC within 30 calendar days of elements that trip due to an actual disturbance, but the time horizon for this requirement is Long-term Planning (which is a planning horizon of one year or longer.) Texas RE suggests that the time horizon should be Operations Planning. Requirement R3 states that the GO shall notify the PC within 30 calendar days of elements that trip due to an actual disturbance, but the time horizon for this requirement is Long-term Planning (which is a planning horizon of one year or longer.) Texas RE suggests that the time horizon should be Operations Planning. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made.
Hydro One	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
Lower Colorado River Authority	Yes	The splitting of requirement for GO and TO was good. It would be more clear if R2 & R3 can directly refer to the protective elements being addressed in Attachment A are the elements to look into when power swings (stable/unstable) occurs. Also, listing some particular in events that power swings would happen can be helpful. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the

Organization	Yes or No	Question 3 Comment
		Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions: Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made. Additionally, the 2^{nd} bullet is not intended to provide the entity specific exclusions to having to evaluate load-responsive protective relays in PRC-026-1 – Attachment A.
American Transmission Company, LLC	Yes	
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Public Service Enterprise Group		This question is a duplicate of the prior question. The response below answers Q3 in the unofficial comment form. R2 and R3 require TOs and GOs, respectively, to notify their Planning Coordinator within 30 days of identifying any Element that trips due to a power swing during a system

Organization	Yes or No	Question 3 Comment
		disturbance due to the operation of load-responsive protective relays. PRC-026-1, as drafted, will have consequences with respect to an entity's implementation of a different standard: PRC-004-3 - Protection System Misoperation Identification and Correction - see http://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-3.pdf. NERC has filed PRC-004-3 with FERC for approval. In summary, PRC-004-3 requires each operation of an interrupting device to be evaluated to determine whether a Misoperation occurred. If such a determination is made, the Protection System owner must investigate the occurrence and either (a) provide a declaration that a cause could not be determined or (b) if a cause is determined, develop and implement a Corrective Action Plan (CAP) or explain why corrective actions are beyond its control or would not improve reliability. PRC-004-3 does not require any action with regard to Element trips that are not Misoperations, i.e., "correct operations." We understand that a Protection System owner would need some documentation to make the distinction between a correct operation and a Misoperation. However, in order to be fully compliant with PRC-026-1 R2 and R3, every Element that trips due to the operation of a load-responsive relay must be evaluated by the entity to determine whether or not the trip was due to a power swing. As discussed on the September 18 webinar on PRC-026-1, the phrase "system Disturbance" has same meaning as the NERC Glossary term for "Disturbance." In other words, "system" is unnecessary. In addition, a "Fault" was stated to be a "Disturbance." Therefore, every operation of a load-responsive relay due to a Fault must be examined under PRC-026-1 to identify whether or not the Element tripped due to a power swing. o If an Elements trips due to a Misoperation, the Misoperation would be investigated under PRC-004-3, and if it was caused by a power swing that could easily be reported under PRC-026-1 as a result of the Protection System owner's compliance with PRC-004-3.

Organization	Yes or No	Question 3 Comment
		Requiring all correct operations be affirmatively evaluated by the Element owner to determine whether they are attributable to a power swing would only "make work" for both the Element owners and their auditors, and the added effort would not improve reliability. Therefore, we propose that the scope of R2 and R3 for correct operations be reduced to a subset of events that are reported to NERC under EOP-004-2 - Event Reporting - see http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf. For example, the Disturbances evaluated in PRC-026-1 for correct operations could be limited to some of the events and associated thresholds listed in EOP-004 - Attachment 1. We believe reasonable events would include: o Automatic firm load shedding on p. 9 o Loss of firm load (preferably limited to non-weather related load loss) on p. 10 o System separation (islanding) on p.10 o Generation loss on p.10, o Complete loss of off-site power to a nuclear plant on p. 10, and o Transmission loss on p.11 To couple the two standards together, NERC, which receives event reports under EOP-004-2, would need to notify the applicable TOs and GOs under PRC-026-1 of the time frame of each event. This would allow the Element owners to evaluate whether any Element trips that occurred during the event and which were correct operations were associated with a power swing. **Response:** The standard drafting team has removed the previous Requirements R2 and R3 (Transmission Owner and Generator Owner) that required notification to the Planning Coordinator, in Requirement R1, of Element trips due to stable or unstable power swings. In deleting Requirements R2 and R3, the standard drafting team revised Requirement R4 (now Requirement R2) for load-responsive relays to be evaluated under two conditions:

Organization	Yes or No	Question 3 Comment
		Notification of an Element pursuant to Requirement R1 where the evaluation of the Element has not been performed in the last five calendar years, or Becoming aware of an Element that tripped in response to a stable or unstable power swing. The standard drafting team has provided supporting detail on the second bullet in the Guidelines and Technical Basis under the heading "Becoming Aware of an Element That Tripped in Response to a Power Swing" on how an entity would "become aware." Changes made. The standard drafting team made revisions to the standard which eliminated the term "Disturbance" as defined by the *Glossary of Terms Used in NERC Reliability Standards*.
Arizona Public Service	Yes	

4. **Requirement R4 (previously R3) contained multiple activities (e.g., demonstrate, develop a Corrective Action Plan, obtain agreement) and was ambiguous. Do you agree that the revision to Requirement R4 now provides a clearer understanding of what is required by the Generator Owner and Transmission Owner for an identified Element? Note: The Criterion is now found in PRC-026-1 – Attachment B, Criteria A and B. If not, please explain why the Requirement is not clear.**

Summary Consideration: Seventy percent of entities commenting agree that the revision to Draft 2, Requirement R4 (now Draft 3, Requirement R2) provides a clearer understanding of what is required by the Generator Owner and Transmission Owner for an identified Element.

There were five minor themes of comments that resulted in a revision to the Standard. First, One comment supported by eight individuals noted that the PRC-026-1 – Attachment B criteria appeared to be part of the Application Guidelines due to the page header. This was an editorial error and has been corrected to correctly include the criteria within the Standard itself. Second, three comments each from individuals requested the Standard Guidelines and Technical Basis include generator based out-of-step protection example for stable power swings. The standard drafting team provided an example. Third, one comment supported by five individuals requested that the re-evaluation period checking load-responsive protective relays against the PRC-026-1 – Attachment B criteria be extended from three to five years. The standard drafting team agreed that the BES would not be expected to change significantly during five years and revised the Requirement to allow a five-year re-evaluation period. Fourth, one comment supported by five individuals were concerned that the Guidelines and Technical Basis was not adequate. The standard drafting team added additional information to improve clarity on applying the PRC-026-1 – Attachment B criteria. Fifth, two comments each from individuals revealed that Draft 2 had an unintended circumstance in that an entity could skip the re-evaluation for an actual event if it had previously evaluated its load-responsive protective relays for a BES Element within the re-evaluation time frame. The standard drafting team agreed that it was important to re-evaluate the load-responsive protective relays for a BES Element for every actual BES Element trip due to stable or unstable power swings regardless of the frequency. The revisions made to Draft 3, Requirement R2 (previously Draft 2, Requirement R4) based on other comments have addressed these problems.

The following summarizes four comment themes that did not result in a change to the Standard. First, four comments represented by 40 individuals commented (includes Questions 1-8) that they would like more flexibility over the criteria in PRC-026-1 – Attachment B. The standard drafting team maintains that the method provided in the PRC-026-1 – Attachment B criteria is well documented, easily implemented, and provides a consistent method for determining a relay's susceptibility to tripping for stable power swings. Requiring Planning Coordinators and possibly Transmission Planners to run additional stability studies to determine a relay's susceptibility to tripping for a stable power swing will be more time consuming than applying the PRC-026-1 – Attachment B criteria. Further, the selected contingency study cases for stability analysis may not produce results to adequately ascertain a relay's susceptibility to tripping for a stable power swing.

Second, three comments represented by 35 individuals suggested removing "full" from the phrase "full calendar months." The standard drafting team disagreed because comments to Draft 1 requested clarification on calendar months and using full make it clear that partial months are not considered in the time frame.

Third, one comment supported by 12 individuals requested that the evaluation time period begin upon receipt of the system impedance data from other entities. The standard drafting team did not agree because the Draft 3, Requirement R2 provides sufficient time to obtain such information, if not already on hand.

Fourth, one comment supported by an individual commented that the Guidelines and Technical Basis does not cover all the load-responsive protective relays in PRC-026-1 protection schemes and configurations. The standard drafting team responded that PRC-026-1 – Attachment B criteria applies to load-responsive protective relays irrespective of the type of protective scheme to which they are applied.

Organization	Yes or No	Question 4 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Is the Criteria a single page (page 17) or is it pages 17-73? **Response:** The standard drafting team corrected the page headers to correctly associate the Attachments A and B with the standard and not the Guidelines and Technical Basis. Change made. The text in the rationale should be included in the Criteria paragraph so that there is no doubt what the evaluation is supposed to demonstrate. **Response:** The standard drafting team revised the Criteria A paragraph to provide additional clarity on what the entity must achieve. Change made. The previous draft (R3) presentation of the demonstration, CAP development, and PC/TP/RC communication was easier to understand just what was expected of the GO and TO. **Response:** The standard drafting team made revisions to the standard based on previous comments and identified problems with the approach in Requirement R3 (Draft 1). The standard drafting team believes that Draft 3 will provide additional clarity over both Drafts 1 and 2. No change made.

Organization	Yes or No	Question 4 Comment
PPL NERC Registered Affiliates	No	R4 should state that the 12-month clock for GOs begins when the TO provides the system impedance data necessary to perform studies, if the GO requests this information from the TO. **Response:** The standard drafting team contends that 12 months is sufficient for evaluating relays (and obtaining other data) based on the conditions that start the time period for the Requirement which are when the entity is notified of an Element or becomes aware of a stable or unstable power swing. No change made. Also, the reference to, "full calendar months," in R4 and Att. B should be changed to just, "calendar months," to prevent confusion. **Response:** The standard drafting team uses the clarifier "full" to be clear that partial months are not counted. For example, if the starting point is in the middle of a calendar month, the entity will have until the end of the last month of the stated period.
Florida Municipal Power Agency	No	See comments in response to Question 8 related to Applicability and responsibility for various requirements. **Response:** The standard drafting team thanks you for your comment, please see response in Question 8.
DTE Electric Co.	No	R4 is clearer in general terms, however, the Criterion and related Guidelines and Technical Basis do not cover all the various relay scheme configurations that may apply. Since specific criteria must be evaluated, the concern is that relay scheme configurations not discussed may result in an incorrect evaluation. **Response:** The standard drafting team notes that Attachment B applies to load-responsive protective relays irrespective of the type of protective scheme to which they are applied. No change made.
FirstEnergy Corp.	No	Attachment B, Criteria A and B might be clearer to a Protection Design Engineer, but are not likely clear to typical compliance personnel.

Organization	Yes or No	Question 4 Comment
		Response: The standard drafting team contends the standard is written so that the performance under the requirements are clear to protection engineering staff that have the expertise to understand the application. Based upon the Measures provided in the Requirements, compliance staff should be able collaborate with their subject matter experts to determine correct and appropriate evidence for compliance. No change made.
Tennessee Valley Authority	No	While an improvement over the previous draft, we believe the time interval for consideration of previous evaluations should be extended to the prior five calendar years. **Response:** Requirement R2 (formerly R4) requires the Generator Owner and Transmission Owner evaluate its load-responsive protective relays on an identified Element by the Planning Coordinator pursuant to Requirement R1, initially and thereafter, where the evaluation has not been performed in the last five (previously three) calendar years. Change made. We also would prefer to see more flexibility in the standard to allow entities to use their preferred methods (not strictly adhering to Attachment B criteria) for determining if a line is likely to trip during a stable power swing. **Response:** The standard drafting team maintains that the method provided in the Criteria of Attachment B is well documented and easily implemented. Additionally, it provides a consistent method for determining a relay's susceptibility to tripping for stable power swings. Requiring Planning Coordinators or Transmission Planners to run additional stability studies to determine a relay's susceptibility to tripping for a stable power swing will be more time consuming than applying the Criteria in Attachment B. Further, the contingencies assessed may not be severe enough to adequately ascertain a relay's susceptibility to tripping for a stable power swing. No change made.
SPP Standards Review Group	No	What is the difference between '12 full calendar months' and '12-calendar months'? Delete the 'full' in Requirement R4.

Organization	Yes or No	Question 4 Comment
		Response: The standard drafting team uses the clarifier "full" to be clear that partial months are not counted. For example, if the starting point is in the middle of a calendar month, the entity will have until the end of the last month of the stated period. In the 3rd line of Requirement R4, change 'Requirement' to 'Requirements'. **Response:** The standard drafting team has revised Requirement R4 (now Requirement R2) such that this issue is resolved. Change made. Refer to our comments in Question #2 as to why we don't agree with the revisions. **Response:** The standard drafting team thanks you for your comment, please see response in Question 2.
Xcel Energy	No	We are generally supportive of the revisions to R4 but offer the following observation. We believe that the way R4 is currently written, an Entity would be allowed to not evaluate an Element's load responsive relays if they had been evaluated in the past three calendar years even if the Element was identified within the last 12 calendar months per R2 or R3 to have tripped in response to a stable power swing. For example, if an element tripped in January 2015 due to a stable power swing, the R4 analysis is performed and corrective action taken per R5 and R6. If the device trips again in 2016 due to a stable power swing, it would appear that there was a problem with the 2015 analysis. But the way R4 is written, the entity would be exempt from performing any analysis or taking any further action until 2018. We do not believe this is the drafting team's intent. **Response:** The standard drafting team thanks you for this keen observation and believes that the revisions made to Requirement R4 (now Requirement R2) address this and other concerns raised in comments. The restructuring of Requirement R4 (now Requirement R2) will require the Generator Owner and Transmission Owner to re-evaluate the load-responsive protective relay should another event occur.
Luminant Generation Company, LLC	No	Luminant agrees that Criteria A (Attachment B) provides a method for determining a relay setting to minimize unnecessary trips due to a stable power swing; however,

Organization	Yes or No	Question 4 Comment
		Luminant recommends that the generation application section include an out-of-step relay example for stable power swings. **Response:** The standard drafting team has provided an out-of-step example in the Guidelines and Technical Basis. Change made. Luminant also recommends removal of unstable power swings from the requirement based on the same comments in question 2. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused approach is based on the PSRPS Report,[19] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team

[19] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 4 Comment
		concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made.
Wisconsin Electric	No	The limitations imposed in the Application Guidelines will not allow a Generator Owner to set an out-of-step relay to properly protect the generator, using commonly applied settings such as for single blinder schemes, and possibly other out-of-step schemes. The settings must be able to detect a power swing in the generator or GSU transformer, which appears to violate the setting limits as in the example of Figure 20. **Response:** The standard drafting team has provided an out-of-step example in the Guidelines and Technical Basis. Change made.
Kansas City Power & Light	No	Attachment A includes Out-of-step tripping. This condition is an unstable power swing and should not be included in the standard. The standard should allow protection relays and philosophies to protect the equipment first and foremost. The requirement not to trip during a stable power swing should be reviewed and considered, but not mandatory if deemed that protection will be sacrificed. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and

Organization	Yes or No	Question 4 Comment
		faults. This standard's focused approach is based on the PSRPS Report,[20] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made.
CPS Energy	No	In general, support Luminant comments. **Response:** The standard drafting team thanks you for your comment, please see response to Luminant.
Lower Colorado River Authority	No	see comments for R4 under application guidelines. **Response:** The standard drafting team thanks you for your comment, please see response in Question 6 concerning the Application Guidelines.
Northeast Power Coordinating Council	Yes	Requirement R4 continues to be a combined TO/GO requirement. For clarity, R4 should also be split into two requirements--one to address the GO obligations by applicable requirement, another to address the TO obligations by applicable requirement. **Response:** The standard drafting team notes that the previous splitting of the Draft 1 Requirement into the Draft 2, Requirements R2 and R3 was intended for clarifying that the "islanding" criteria was only related to the Transmission Owner. The evaluation of load-responsive protective relays under the new Requirement R2 (previously

[20] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Yes or No	Question 4 Comment
		Requirement R4) applies to both the Generator Owner and Transmission Owner in evaluating the 120 degree separation angle.
Arizona Public Service Co	Yes	
Puget Sound Energy	Yes	
Colorado Springs Utilities	Yes	
Duke Energy	Yes	
ISO RTO Council Standards Review Committee	Yes	The SRC agrees that the revisions have provided clarity; however, notes the inconsistency within the standard regarding describing GO and TO requirements separately in Requirements R2 and R3. **Response:** The standard drafting team notes that the previous splitting of the Draft 1 Requirement into the Draft 2, Requirements R2 and R3 was intended for clarifying that the "islanding" criteria was only related to the Transmission Owner. The evaluation of load-responsive protective relays under the new Requirement R2 (previously Requirement R4) applies to both the Generator Owner and Transmission Owner in evaluating the 120 degree separation angle.
Dominion	Yes	
JEA	Yes	
Seattle City Light	Yes	Seattle appreciates the effort of the drafting team to separate auditable activities into an individual requirement or subrequirement rather than blending them together. **Response:** The standard drafting team thanks you for your comment.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	Yes	We agree the requirement is much clearer. **Response:** The standard drafting team thanks you for your comment.
Bonneville Power Administration	Yes	BPA agrees that Attachment B is an improvement; however, it could be better. It appears that the only way to verify compliance is through a graphical comparison of the relay characteristic and a lens characteristic that is described in the Application Guidelines. The Application Guidelines give one example of calculating six sample points on the lens characteristic. BPA was able to work our way through the example, but it was somewhat difficult and required lots of reading between the lines. BPA requests more explicit explanations of what is expected to show compliance and how to develop the lens characteristic. **Response:** More detailed point calculations have been added to the Application Guidelines to show more point-by-point calculations of the lens (see Figures 5a, 15d, 15h, and 15i). Change made.
Oncor Electric Delivery LLC	Yes	
Public Service Enterprise Group	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
City of Tallahassee	Yes	

Organization	Yes or No	Question 4 Comment
Idaho Power	Yes	
ISO New England	Yes	
Pepco Holdings Inc.	Yes	The requirement as written in the latest draft version of the standard is clear on what actions must be taken. The 12 month timeline is reasonable. **Response:** The standard drafting team thanks you for your comment.
Nebraska Public Power District (NPPD)	Yes	
Tacoma Power	Yes	
Ameren	Yes	
ITC	Yes	
Texas Reliability Entity	Yes	No comments.
Hydro One	Yes	Please refer to comments for 6. **Response:** The standard drafting team thanks you for your comment, please see response in Question 6.
Hydro One	Yes	Refer to 6. **Response:** The standard drafting team thanks you for your comment, please see response in Question 6.
Manitoba Hydro	Yes	

Organization	Yes or No	Question 4 Comment
American Transmission Company, LLC	Yes	
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Consumers Energy Company	Yes	

5. **The new Requirement R5 (previously R4) and the new Requirement R6 address Corrective Action Plans (CAP), if any. Do you agree this is an improvement over having the development of the CAP comingled with another Requirement? If not, please explain.**

Summary Consideration: More than half of the entities that commented agree that Draft 2, Requirements R5 and R6 were an improvement over the previous Draft 1. The following summarizes the comments received starting with the comments that resulted in a change to the Standard and followed by a summary of comments that did not result in a change to the Standard.

There were three significant themes of comments that resulted in a revision to the Standard. First, twelve comments represented by 25 individuals were concerned that the Corrective Action Plan (CAP) was limited to only modifying the Protection System and did not provide an alternative. The standard drafting team modified the Draft 2, Requirement R5 (now Draft 3, Requirement R3) to make it clear that the development of a CAP may include; 1) modifications to the Protection System to meet the PRC-026-1 – Attachment B criteria, 2) modifications to the system configuration (e.g., splitting a bus such that the Protection System meets the PRC-026-1 – Attachment B criteria), and 3) modifications so that the Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

Second, five comments supported by 35 individuals were concerned that 90 calendar days was insufficient for determining corrective actions for inclusion in a CAP. Entities are concerned that development of the necessary modifications could be very complex and take longer than 90 calendar days. The standard drafting team agreed and extended the time period for developing the CAP to six full calendar months.

Third, one comment supported by ten individuals requested that evidence retention periods be set to 12 calendar months to be consistent with the Reliability Assurance Initiative (RAI). The standard drafting team consulted with NERC staff and made the revisions.

The following summarizes four comments that did not result in a change to the standard. First, two comments represented by 25 individuals requested that the Generator Owner and Transmission Owner have a Requirement to provide notification of the status of its CAP to the Planning Coordinator. The standard drafting team disagreed because such notification is administrative and has limited reliability benefit for something entities may request on their own outside of the Standard.

Second, two comments supported by 11 individuals believed that the Draft 3, Requirement R4 (previously Draft 2, Requirement R6) to implement the CAP is administrative due to updating actions and timetables to demonstrate compliance. The standard drafting team disagreed that updating paperwork is not the intent and is not the sole source for having evidence of implementation. Updating actions and timetables are an essential part of the CAP for when the actions (i.e., tasks) that are required to remedy the problem change. Implementation may be demonstrated by providing work order showing a particular action (i.e., task) was completed, but the work order was not necessarily updated as "complete" in the CAP or tracking system.

Third, two comments supported by six individuals were concerned that a CAP could be required under both PRC-004[21] and this PRC-026 Standard. The standard drafting team agrees that in rare cases, the entity may be doing a CAP in both Standards. An entity may use a single CAP to demonstrate compliance with both Standards or create separate CAPs. In some cases, an entity's CAP for resolving a Misoperation could be different from a longer term CAP for meeting the reliability purpose of PRC-026-1.

Fourth, two comments each from individuals believe that a CAP would prevent the Protection System from tripping for unstable power swings. The standard drafting team noted that the Standard does not preclude tripping for unstable power swings.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	A CAP is developed to correct a problem after the requirements of a standard are implemented. The Implementation Plan should address meeting the obligations of the standard's requirements. The Implementation Plan would also address the annual identification of Elements. This would allow for the removal of requirements R5 and R6. Generator Owners and Transmission Owners need more time subsequent to the identification of load-responsive protective relays to perform a thorough evaluation. The requirement should provide at least 180 days to perform the evaluation. This will allow for a more complete response than can be obtained in 60 days. If the CAP is kept, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. The length of time an entity has to complete corrective actions should be specified. 180 calendar days is a realistic length of time.

21

Organization	Yes or No	Question 5 Comment
		Response: Thank you for your comment. The standard drafting team has extended the time for the Corrective Action Plan (CAP) development to six calendar months. The length of time to implement the CAP is included in the CAP. Change made. Response: The standard drafting team contends notification of the CAP has no reliability benefit and would only add to the compliance burden as an administrative function.
Puget Sound Energy	No	It should be recognized in the requirement that the appropriate response to a trip due to a stable power swing might be to take no action. The requirement should be amended to allow the Element owner to make a declaration that corrective action would not improve BES reliability, therefore action will not be taken, consistent with PRC-004-3, R5. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern	No	Already discuss in Q4 comment - the requirement to develop a CAP was clear either way. The addition of the 60 day due date added more detail. **Response:** Thank you for your comment.

Organization	Yes or No	Question 5 Comment
Company Generation and Energy Marketing		
Colorado Springs Utilities	No	We agree with the Public Service Electric and Gas Company comments. **Response:** The standard drafting team thanks you for participating, please see the responses to Public Service Enterprise Group.
ISO RTO Council Standards Review Committee	No	We agree with consolidating the Corrective Action Plan obligations into Requirements R5 and R6. However, the SRC recommends that, for R5, Generator and Transmission Owners need more time to develop a thorough CAP that addresses identified issues with load-responsive protective relays. The requirement should provide at least 180 days to develop the Corrective Action Plan, which would will allow for a more complete and thoughtful response than can be obtained in 60 days. **Response:** Thank you for your comment. The standard drafting team has extended the time for the Corrective Action Plan (CAP) development to six calendar months. The length of time to implement the CAP is included in the CAP. Change made. Also under R5, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. Right now, the requirement is open ended without the provision of Corrective Action Plan information. **Response:** The SDT contends notification of the CAP has no reliability benefit and would only add to the compliance burden as an administrative function.
Dominion	No	No date is given for CAP implementation. Is it acceptable to work the CAP in with projects regardless of project execution date? (3-7 years, if no project is in place at the specific location; is it acceptable to implement the CAP once a project arises?) **Response:** In the event that a Corrective Action Plan (CAP) is necessary based on future system conditions, the CAP can specify a time frame that does not enact changes until the actual system modifications will be made. No change made.

Organization	Yes or No	Question 5 Comment
PPL NERC Registered Affiliates	No	: The deadline of 60 calendar days for development of a Corrective Action Plan should be changed to six months. Many GOs do not have Protection System design expertise, and the process of making a business case for the expenditure of hiring a contractor, getting this request approved, exploring alternatives, making a technical selection and again obtaining management approval can take far more than sixty days. **Response:** Thank you for your comment. The standard drafting team has extended the time for the Corrective Action Plan (CAP) development to six calendar months. The length of time to implement the CAP is included in the CAP. Change made.
Florida Municipal Power Agency	No	FMPA agrees with the separation of R5 and R6. However, R5 pre-supposes and furthermore directs that the only acceptable Corrective Action Plan is one which involves modifying the Protection System. There are a number of other ways to improve stability performance which are therefore ruled out. In fact, improving the performance to, and reducing the severity of power swings that result from a given event should be a preferential solution as it has a much wider impact on the stability and the reliability of the system. It may be true that modifications to microprocessor relay settings or even replacement of relays might be the least cost or the fastest and simplest solution, that in no way should dictate that the standard should mandate this be the only corrective action employed. **Response:** Thank you for your comment. The standard drafting team has modified the requirement so that a Corrective Action Plan (CAP) can include any modifications that ensure that the Protection Systems meet the criteria in Attachment B. Change made.
ACES Standards Collaborators	No	We agree splitting the requirement into two requirements where one deals with assessing the Protection System and the other deals with developing a CAP is an improvement. However, we continue to believe the Requirement R6 is an administrative requirement that meets P81 criteria and should be removed. The only way the R6 will ever be violated is if an entity fails to update their paperwork on the CAP. How does failing to update documentation not administrative?

Organization	Yes or No	Question 5 Comment
		Response: The standard drafting team intends the entity to be capable of demonstrating implementation of a Corrective Action Plan (CAP) based on evidence specified in the Measure. For example, evidence showing completion of the various actions of the CAP would demonstrate the entity's effort toward remedying the specific problem. The updating of actions and timetables in Requirement R4 (previously Requirement R6) is not intended to specify an administrative exercise to show compliance with implementation. The updating of actions and timetables refers to the entity revising the CAP during the implementation as needed following its initial development. The standard drafting team has suggested to NERC Compliance modifications to the Reliability Standard Audit Worksheet (RSAW) in the approach section to Requirement R4 (previously Requirement R6) concerning the implementation of the CAP. How does ensuring the documentation is updated by enforcing penalties serve reliability? How is this consistent with RAI which is intended to refocus compliance and enforcement on those risks most important to reliability and not on documentation issues? **Response:** The standard drafting team has revised the minimum periods to retain evidence to 12 calendar months in the Evidence Retention section to address Risk Assurance Initiative (RAI) concerns. Change made.
Public Service Enterprise Group	No	The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element).

Organization	Yes or No	Question 5 Comment
		Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
Seminole Electric Cooperative, Inc.	No	Requirement R5 requires the development of a CAP. Seminole requests that the ability to submit a notification to the Entity's RRO, stating why a CAP cannot or should not be implemented, be added to R5. Seminole reasons that there may be instances where a CAP is not possible, somewhat akin to a TFE in the CIP-world. The SDT could make the CAP exception contingent on the RRO's approval. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
Independent Electricity System Operator	No	The scope of the proposed standard is directed at blocking the trip for stable power swings only. However, since existing distance schemes have the ability to trip for both stable and unstable swings, the standard can be interpreted as permitting a Transmission Owner to remove both trip abilities in order to comply with this standard. Removing the trip abilities for unstable power swings may have unintended consequences, such as preventing successful self-generating islands to form, making the restoration process much more difficult. In order to prevent any unintended consequence, we suggest that Requirement 5 is modified to have the Transmission Owner consult with the Planning Coordinator for whether out-of-step protection is needed, and if so, whether out of step tripping or power swing blocking should be applied: R5. Each Generator Owner and Transmission Owner shall, within 60 calendar days of an evaluation that identifies load-responsive protective relays that do not meet the PRC-026-1 - Attachment B Criteria pursuant to Requirement R4, develop a Corrective Action

Organization	Yes or No	Question 5 Comment
		Plan (CAP) to modify the Protection System to meet the PRC-026-1 - Attachment B Criteria while maintaining dependable fault detection and dependable out-of-step tripping. (Each Generator Owner and Transmission Owner shall consult with their applicable Planning Coordinator if out of-step tripping should be applied at the terminal of the Element). **Response:** A Corrective Action Plan (CAP), when implemented, does not preclude the relay from tripping in response to an unstable power swing. The standard drafting team contends that any out-of-step tripping requirements would be identified independent of this standard and, if required, would need to remain in service. This standard is not intended to create a requirement to prevent out-of-step tripping for unstable power swings nor to evaluate where out-of-step tripping should be applied. It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the concern stated in Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Identification of Elements is a screen to identify Elements with load-responsive protective relays that are subject to the Requirements of the standard. No change made.
Wisconsin Electric	No	Similar to PRC-004-3 R5, the entity should be allowed to explain in a declaration why corrective actions would not improve BES reliability and that no further corrective actions will be taken. For overall BES reliability, It must be left to the equipment Owners to determine when relay settings which do not meet the Application Guidelines must still be used for proper equipment protection. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 –

Organization	Yes or No	Question 5 Comment
		Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
City of Tallahassee	No	The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
ISO New England	No	For R5, Generator and Transmission Owners need more time develop a Corrective Action Plan. The requirement should provide at least 180 days to develop the Corrective Action Plan. This will allow for a more complete and thoughtful response than can be obtained in 60 days. **Response:** Thank you for your comment. The standard drafting team has extended the time for the Corrective Action Plan (CAP) development to six calendar months. The length of time to implement the CAP is included in the CAP. Change made. Also under R5, the Generator or Transmission Owner should provide a copy of the initial Corrective Action Plan and status updates to the Planning Coordinator. Right now, the requirement is open ended without the provision of Corrective Action Plan information.

Organization	Yes or No	Question 5 Comment
		Response: The standard drafting team contends notification of the Corrective Action Plan (CAP) has limited reliability benefit, if any, and would only add to the compliance burden as an administrative function. No change made.
Kansas City Power & Light	No	Out-of-step tripping and tripping for unstable power swings are intended results. Corrective Action Plans are not needed for these events. **Response:** A Corrective Action Plan (CAP), when implemented, does not preclude the relay from tripping in response to an unstable power swing. The standard drafting team contends that any out-of-step tripping requirements would be identified independent of this standard and, if required, would need to remain in service. There is no requirement to create a CAP to prevent tripping for unstable power swings. It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the concern stated in Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Identification of Elements is a screen to identify Elements with load-responsive protective relays that are subject to the Requirements of the standard. No change made.
CPS Energy	No	In general, support PSEG comments. **Response:** The standard drafting team thanks you for participating, please see the responses to the Public Service Enterprise Group.
Ameren	No	Ameren adopts the following comment submitted by PSEG. The requirement to develop a CAP in R5 should be amended to allow the Element owner, in lieu of a developing a CAP, to make a declaration that corrective actions would not

Organization	Yes or No	Question 5 Comment
		improve BES reliability and therefore will not be taken. This is consistent with PRC-004-3, R5. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
ITC	No	A “no CAP declaration” should be added to R5. This option is necessary when enabling power swing blocking affects the BES reliability. An example is for a Slow Trip - During Fault, in which the high-speed protection scheme has been identified to meet the dynamic stability performance requirements of the TPL standards. As ITC stated in Draft 1, we are concerned about load/swings with subsequent phase faults which result in time-delayed tripping when power swing blocking is enabled. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability. In cases where tripping for a fault that occurs while out-of-step blocking is enabled is a concern, then other methods may need to be considered in order to meet the criteria of Attachment B.
Lower Colorado River Authority	No	R5(part of the previously R3), missed the alternative options in previously R3 which allows entities owner to obtain agreement from planning coordinator, if a dependable fault detection or out of step tripping cannot be achieved.

Organization	Yes or No	Question 5 Comment
		Response: The standard drafting team contends that relays that do not meet Attachment B criteria can be modified by changing relay settings or changing the Protection System to meet the criteria. Attachment B includes an alternative method to meet the criteria at a system separation angle less than 120 degrees. No change made. R5 in application guideline asks to "develop" and "complete" the CAP, while R5 in the standard only ask to "develop" within 60 cal day time period. **Response:** The standard drafting team deleted the "complete" from the Guidelines and Technical Basis. Note that Requirement R5 is now Requirement R3. Change made. It's ambiguous with R6 in the standard which asks to "implement" the CAP without any specific time period. And i assume this is to allow the "implementation" to be occur during next available plant outage. **Response:** The Corrective Action Plan (CAP) has its own timetable and set of actions that are determined by the entity. The work necessary under the CAP may vary greatly depending on the work being performed; therefore, the standard drafting team has not specified any time frames. No change made.
CenterPoint Energy	No	CenterPoint Energy recommends that requirements for Corrective Action Plans (CAP) be removed in the draft PRC-026-1 standard. The operation of a Protection System during a non-fault condition due to a stable power swing would be a reportable Misoperation under PRC-004. Both the current enforceable version of PRC-004 and the one under development require a CAP for a Misoperation. Consistent with one of the recommendations from the NERC Industry Experts initiative, CenterPoint Energy believes that there should not be duplicative requirements in NERC Reliability Standards. **Response:** The Corrective Action Plan (CAP) would be required under PRC-004[22] for an identified Misoperation; however, for an Element that trips due to a stable or unstable power swing whether or not it was a Misoperation, a CAP would be required under PRC-

[22] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 5 Comment
		026-1 if the entity determined that its load-responsive protective relays did not meet PRC-026-1 – Attachment B criteria. No change made.
Arizona Public Service Co	Yes	
Duke Energy	Yes	Duke Energy agrees that this an improvement from the previous draft. However, we seek guidance or clarification on the boundaries between PRC-026-1 and PRC-004-3. When Misoperations occur due to a stable power swing, a CAP is required to be developed pursuant to R5 of PRC-004-3. Would the evaluation and, if needed, Corrective Action Plan from PRC-026-1 R4 through R6 be acceptable as use for the CAP required in PRC-004-3 R5? **Response:** A Corrective Action Plan (CAP) would be required pursuant to PRC-004[23] if a Misoperation has occurred. If the CAP is developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element), then it could also be used for PRC-026-1. It is up to the discretion of the entity as to how it demonstrates compliance with the CAP requirements in each standard.
JEA	Yes	
DTE Electric Co.	Yes	
FirstEnergy Corp.	Yes	Assuming a situation results in the need for a CAP, what is the purpose of stating that dependable fault detection (and out-of-step tripping if applied) shall be maintained while developing the CAP? Maintenance and testing of protection is covered in PRC-005, and any failure of existing protection is addressed by PRC-004. Why is there further need to address maintaining

[23] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 5 Comment
		existing protection, and how is such a requirement measured in the context of PRC-026-1? Also, what is the anticipated mechanism for tracking and reporting progress on a CAP? **Response:** The standard drafting team included the clause "dependable fault detection (and out-of-step tripping if applied)" to express that certain protection may not simply be disabled to comply with this standard. The standard requires the development and implementation of a Corrective Action Plan (CAP) to, by definition, which is "[a] list of actions and an associated timetable for implementation to remedy a specific problem." In this case, to ensure that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). There is no tracking and reporting of a Corrective Action Plan (CAP) progress to other parties. The entity must demonstrate implementation of its CAP(s). No change made.
Tennessee Valley Authority	Yes	
Seattle City Light	Yes	Seattle appreciates the effort of the drafting team to separate auditable activities into an individual requirement or subrequirement rather than blending them together. **Response:** Thank you for your support.
Bonneville Power Administration	Yes	
Oncor Electric Delivery LLC	Yes	
Entergy Services, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
American Electric Power	Yes	
Xcel Energy	Yes	The VSLs for R4 and R5 seem inconsistent. Entities are given 12 calendar months to perform an analysis with VSLs of increasing severity for being <30, <60, <90, and > 90 days past due. They are given 60 days to develop a CAP following completion of an evaluation that determines the need for a protection system modification to meet PRC-026-1 Attachment B criteria, and with an R5 VSL of increasing severity for being <10, <20, <30 or >30 days past due in the development of a CAP. Given the 12 month leeway on the completion of analysis following identification of the Element and the only 60 day leeway on CAP development, why would an entity sign off an R4 analysis as complete for an element requiring a protection system modification prior to the 12 month deadline, essentially starting the 60 day clock on the CAP development R5 requirement? We recommend that all R4 analysis completion and R5 CAP development timeframes be based on the calendar months from the original date of identification of the susceptible Element and that the same <30 day, <60 day, <90 day and >90 day increments be used both R4 and R5 VSLs. This approach would eliminate any potential benefit from delaying the officially acknowledged date of completion of the R4 analysis and not have any effect on the final R5 max CAP development timeframe (ie. months since initial Element identification) allowable by the standard. **Response:** Thank you for your comment. The standard drafting team considered your suggested approach, but contends that the current approach is more concise. The standard drafting team has extended the time for the Corrective Action Plan (CAP) development to six calendar months. The length of time to implement the CAP is included in the CAP. Change made.
Luminant Generation Company, LLC	Yes	
Idaho Power	Yes	

Organization	Yes or No	Question 5 Comment
Pepco Holdings Inc.	Yes	The requirement as written in the latest draft version of the standard is clear on what actions must be taken. The 12 month timeline is reasonable. **Response:** The SDT thanks you for your support.
Nebraska Public Power District (NPPD)	Yes	We agree that separation of the CAP requirement is an improvement; however, we feel there should be a caveat to this requirement. The standard as written could result in reduced sensitivity of fault detection settings, which would interfere with "maintaining dependable fault detection". We believe there should be an option to maintain our ability to operate the BES in a reliable manner and still remain in compliance with R5. This requirement seems like double-jeopardy. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.
Tacoma Power	Yes	
Texas Reliability Entity	Yes	No comments.
Hydro One	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 5 Comment
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	The requirement to develop a CAP in R5 should be edited to allow the owner to make a declaration that corrective actions would not improve BES reliability if that is the case and therefore action will not be taken. This is consistent with PRC-004-3, R5. **Response:** The standard drafting team contends that all trips in response to stable power swings require the relays to be evaluated and, if required, a Corrective Action Plan (CAP) be developed so that the Protection System meets the PRC-026-1 – Attachment B criteria while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element). Eliminating unnecessary future tripping of Elements in response stable power swings does improve BES reliability.

6. **Does the "Application Guidelines and Technical Basis" provide sufficient guidance, basis for approach, and examples to support performance of the requirements? If not, please provide specific detail that would improve the Guidelines and Technical Basis.**

Summary Consideration: Slightly less than half of the entities that commented agreed that the Application Guidelines and Technical Basis" provide sufficient guidance, basis for approach, and examples to support performance of the Requirements. The following summarizes the comments received starting with the comments that resulted in a change to the Standard and followed by a summary of comments that did not result in a change to the Standard.

There were two significant themes of comments that resulted in a revision to the Standard. First, twelve comments supported by 38 individuals requested clarifications in Guidelines and Technical Basis. The standard drafting team provided additional discussion, figures, and tables. Second, three comments represented by 24 individuals suggested a number of editorial, formatting, and style edits for the Guidelines and Technical Basis. The standard drafting team implemented corrections those items that were errors and consistent with the NERC style guide for writing.

There were two minor themes of comments that did not result in a revision to the Standard. First, one comment supported by six individuals questioned the Standard's exclusion of relays with a time delay greater than 15 cycles with regard to slip rates. The standard drafting team noted that a time delay of 15 cycles was chosen because it equates to a conservatively low, stable power swing slip rate of 0.67 Hz. As a consequence of using this slip rate and corresponding time delay, most zone 2 relays are excluded. Second, one comment represented by five individuals had general questions or observations. The standard drafting team provided informative feedback to questions and observations.

Organization	Yes or No	Question 6 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi	No	The calculations, requiring the extent of material provided in the application guide to explain, appear to be quite complex and difficult. Is the SDT open to considering an alternative method of evaluation? It is proposed that GO or TO give relay settings to the entity with the transient analysis modeling tool (TP/PC), and that entity determine if the GO/TO relay settings need to be modified

Organization	Yes or No	Question 6 Comment
Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		based on the power swing characteristics and simulation results for the area being reviewed. **Response:** The standard drafting team maintains that the method provided in the Criteria of Attachment B is well documented and easily implemented. Additionally, it provides a consistent method for determining a relay's susceptibility to tripping for stable power swings. Requiring Planning Coordinators or Transmission Planners to run additional stability studies to determine a relay's susceptibility to tripping for a stable power swing will be more time consuming than applying the Criteria in Attachment B. Further, the contingencies assessed may not be severe enough to adequately ascertain a relay's susceptibility to tripping for a stable power swing. Also, additional "communication" Requirements would have to be added to the Standard requiring the Generator Owner or Transmission Owner to provide relay settings to the Planning Coordinator or Transmission Planner and requiring the Planning Coordinator or Transmission Planner to provide the results of their studies back to the Generator Owner or Transmission Owner. Each of these new Requirements would need time horizons giving each applicable entity a limited amount of time to communicate the pertinent data. These new Requirements would add additional compliance burden to the Applicable Entities. No change made.
Dominion	No	Under Criterion R4, 'Exclusion of Time Based Load-Responsive Protective Relays,' the calculations here are ambiguous. PRC-026-1 Attachment A explicitly states we are to evaluate protective functions listed with a delay of 15 cycles or less; however, there is small section outlining the need to calculate what sort of delays should be evaluated under different slip frequencies. Adding the 'Exclusion of Time Based Load-Responsive Protective Relays' section is counter-productive in its current context. Dominion suggests that the SDT revise the section to make it more understandable or remove it. No section discusses slip frequencies ranges. The WECC experiences 0.25-0.28 Hz north-south oscillations, ERCOT experiences 0.6 Hz north-south and 0.3 Hz east-west, Tennessee to Maine experiences 0.2 Hz oscillations, but Tennessee to Missouri experiences 0.7 Hz oscillations. Roughly 0.01 to 0.8 Hz oscillations are associated with

Organization	Yes or No	Question 6 Comment
		wide area oscillations, but 3.0 to 10 Hz oscillations are associated with FACTS devices that may cause wide or local. What is the acceptable range of oscillations this standard is meant to cover? **Response:** The "Exclusion of Time Based Load-Responsive Protective Relays" section in the Application Guidelines is a technical justification for excluding load-responsive protective relays that have a time delay of 15 cycles or greater. It does not require an Entity to evaluate relay time delays for varying system slip rates. Various relay time delays were evaluated for an expected worst case stable power swing that enters a mho characteristic at a system angle of 90 degrees and turns back around 120 degrees. The total traversal time (relay time delay) was then converted to a system slip rate for comparison purposes. The time delay of 15 cycles was chosen because it equates to a conservatively low, stable power swing slip rate of 0.67 Hz. As a consequence of using this slip rate and corresponding time delay, most zone 2 relays are excluded. The slip rate analysis was done to validate a minimum time delay that could be used to exclude certain load-responsive relay elements (e.g., zone 3 mho, zone 4 mho, phase time overcurrent, etc.), that are set with larger reaches and longer time delays. The Standard is not establishing minimum or maximum slip rate criteria that must be adhered to. The chosen time delay is not intended to cover all possible slip rates.
JEA	No	This standard is not necessary and we agree with the analysis of the NERC SPCS that it may have unintended consequences which could decrease the reliability of the BES. **Response:** The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[24] in the introductory remarks regarding the need for a standard to meet regulatory directives.
Florida Municipal Power Agency	No	FMPA commends the drafting team on the amount of material that has been developed to support the Application of this standard. The various examples used in the

[24] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Yes or No	Question 6 Comment
		Application Guide are generally good example scenarios. However, the focus of the Guide seems to be more on repetitive demonstration of basic equations and less on the SDT's expected interpretation of various scenarios. One full sample of all the calculations in one scenario is all that is required. Each time the equations are repeated it takes roughly 11 pages. **Response:** The standard drafting team has left the detailed calculations for the six critical points of the lens characteristic. No change made. In general there are a lot of pages of basic equations and very little "guidance" within the examples. Furthermore, the examples seem to have been developed to make a supporting case for the Criteria of Attachment B but there is no true discussion of how these examples should be interpreted to support the Criteria. An easy example of this is Table 10, where the impact of the system transfer impedance on the lens characteristic is tabulated, but there is no use of that data to explain why all transfer impedances, no matter what the magnitude, should be completely ignored. The data is there, but the expectations regarding interpretation of the data are more important, and these are missing. **Response:** More detail has been added to the Application Guidelines to better clarify the equations. Additionally, a clarifying paragraph has been added with a discussion of the data in Table 10. Change made. A couple of additional issues that FMPA believes should be cleaned up. o The first full paragraph of Page 28 of the Application Guidelines describes the modeling of generator reactances in stability models, but there is no segue regarding why this information was presented. Please clarify that the intent of the paragraph is to make it clear that the reactances that are used by TP's/PCs (unsaturated reactances) may not be the same reactances as the ones that are being recommended for use in the application of the criteria (saturated reactances). **Response:** A clarifying paragraph has been added to the Application Guidelines after the paragraph mentioned above. Change made.

Organization	Yes or No	Question 6 Comment
		o The Application Guide makes frequent reference to "pilot zone 2 element" in the figures. Strictly speaking the figures show an example of a "distance" or "impedance" mho relay characteristic curve. The term "pilot" refers colloquially in protection to a communication assisted scheme, which may be used in conjunction with a mho characteristic or may not. The use of this term introduces confusion because Attachment A specifically excludes "pilot wire relays", which are a specific sub-set of transmission relay that does not use a mho characteristic. **Response:** The figures have been updated to generically refer to Pilot Zone 2 and Zone 2 impedance characteristics as "mho element characteristics." A clarifying paragraph has also been added discussing the types of "pilot" or communications relay schemes that need to be considered. Change made.
DTE Electric Co.	No	While considerable discussion and examples have been provided, there are variations in relay types and schemes that are not specifically covered. Perhaps these variations could be submitted at some point for review and application guidance. **Response:** The standard drafting team agrees that there are various relay types (e.g., mho, quadrilateral, lens, loss of field, out-of-step, over current, etc.) that must meet the criteria of this Standard. The standard drafting team attempted to illustrate the application of the criteria in PRC-026-1 – Attachment B using only the most common relay types for brevity. There are other types of relays not specifically discussed in the Application Guidelines, but the criteria in PRC-026-1 – Attachment B can be applied to them similarly.
SPP Standards Review Group	No	Insert a 'to' between 'pursuant' and Criterion' in the 3rd line up from the bottom of the paragraph on Criterion 1.In the 9th line in the 1st paragraph under Criterion 4, capitalize 'Criterion'. In Figures 1 and 2, change 'Criterion five' to 'Criterion 5'.In the 7th line of the paragraph following Figures 1 and 2, change 'included' to 'include'. **Response:** Changes made.

Organization	Yes or No	Question 6 Comment
		In the 8th line of the paragraph under Requirement R4, delete 'full' and hyphenate '12-calendar'. **Response:** The SDT is retaining the word "full." Change not made. In the 5th line of the 2nd paragraph under Exclusion of Time Based Load-Responsive Protective Relays, insert 'degrees' between '120' and 'before'. **Response:** Change made. In the 3rd line of the paragraph immediately following Table 1, capitalize 'Zone'. **Response:** Changes made. In the 15th line of the same paragraph, delete the same phrase in the parenthetical. **Response:** The standard drafting team could not locate the source of the comment. In the 4th line of the paragraph following Equation (3), replace 'plus and minus' with a '+/-'. **Response:** Change made. Capitalize 'Zone 2' in the captions of Figures 10, 11, 12, and 15. **Response:** Changes made. In that same paragraph, capitalize 'Zone 2'. **Response:** Change made. In the last line of the 2nd paragraph under Application to Generation Elements, replace 'Requirement' with 'Requirements'. **Response:** Change made. Capitalize 'Zone 2' in the 1st line of Example R5a. **Response:** Change made. Capitalize 'Zone 2' in the 1st line of Example R5c.

Organization	Yes or No	Question 6 Comment
		Response: Changes made.
Seattle City Light	No	Seattle appreciates the efforts of the drafting team to provide application guidance and technical basis information and welcomes the trend towards such implementation documentation throughout the standards development process. For PRC-026, this material has improved somewhat compared to the original draft, but application of the standard remains insufficiently clear for Seattle to recommend an affirmative ballot at this time. More examples and/or a flow chart or something similar to fully delineate the steps in the process are wanted. **Response:** Thank you for your comments. The standard drafting team has made changes to the Standard to clarify industry issues. We don't believe that the Requirements of the Standard require a flow chart. More clarifying examples have been added to the Application Guidelines.
ACES Standards Collaborators	No	(1) The "Application Guidelines and Technical Basis" are quite helpful and definitely do provide additional insight into the meaning of the requirements. However, we believe additional modifications are necessary. (2) On page 18 in the second paragraph, we do not believe the paragraph captures all of the reasons for changing the applicability of the standard. We believe that changing the applicability makes that standard consistent with the other relay loadability standards and makes the standard consistent with the functional model. These reasons are important to capture as they are more substantial than those listed. **Response:** The standard drafting team agrees and has incorporated the change in the Introduction section. Change made. (3) In the Requirement R1 paragraph on page 20, please change "and other NERC Reliability Standards" to PRC-006. There are two main standards (or five depending on which version of TPL are used) that drive identification of Elements susceptible to stable power swings. They are the UFLS standards and TPL standard(s). As written, this paragraph is too open ended and could lead to confusion.

Organization	Yes or No	Question 6 Comment
		Response: The standard drafting team has added a reference to PRC-006 and left the reference to “other NERC Reliability Standards” to capture future Standards that may be developed or existing Standards that may be modified. Change made. (4) We suggest that a diagram should be developed depicting the example in the second paragraph on page 24. **Response:** Requirements R2 and R3 were removed and their intent (actual events) is now captured in Requirement R2 (previously Requirement R4). The paragraph referring to the formation of an island in the R2 section of the Application Guidelines has been removed. Change made. (5) In the “lens characteristic” examples, we suggest that annotating the figure with the actual lens point would be helpful in understanding the “lens characteristic”. **Response:** More detailed point calculations have been added to the Application Guidelines to show more point-by-point calculations of the lens (see Figures 5a, 15d, 15h, and 15i). Change made.
Bonneville Power Administration	No	BPA agrees that Attachment B is an improvement; however, it could be better. It appears that the only way to verify compliance is through a graphical comparison of the relay characteristic and a lens characteristic that is described in the Application Guidelines. The Application Guidelines give one example of calculating six sample points on the lens characteristic. BPA was able to work our way through the example, but it was somewhat difficult and required lots of reading between the lines. BPA requests more explicit explanations of what is expected to show compliance and how to develop the lens characteristic. **Response:** More detailed point calculations have been added to the Application Guidelines to show more point-by-point calculations of the lens (see Figures 5a, 15d, 15h, and 15i). Change made.
Xcel Energy	No	In the Application Guidelines, Criteria 1 uses the term “operating limit” and Criteria 2 uses the term “System Operating Limit” although both are identified by the existence

Organization	Yes or No	Question 6 Comment
		of angular stability constraints, seemingly defining the same type of operating constraint, i.e. operating limit. Xcel Energy would suggest either explaining the difference between the terms "operating limit" and "System Operating Limit", or eliminating the potentially duplicative criterion, since a "Generator" can be an "Element". **Response:** The standard drafting team replaced the term "operating limit" with "System Operating Limit (SOL)" in Criterion 1 to be consistent with Criterion 2. Criterion 1 identifies generators and Elements terminating at the Transmission station associated with the generator(s), while Criterion 2 identifies transmission Elements that are monitored as part of an SOL. Change made. The lens calculation tool is not validated or authorized for use. Due to the hypothetical nature of the calculations, a standardized tool should be provided so that industry can achieve consistent results. **Response:** It is each Entity's responsibility to obtain or create necessary tools to prove compliance with NERC Standards. The Application Guidelines sufficiently document and detail the necessary calculations to prove compliance. Additionally, a sample tool has been made available on the PRC-026-1 project page to help guide entities. No change made. There is no requirement that the TO provide the System Equivalent to the GO. This Standard should provide communication requirements between the GO and TO, similar to the MOD series standards effective inn 2014. While this may not be necessary due to the typically amenable working relationships in a vertically integrated utility, it may be required in areas that are served by several companies. **Response:** The standard drafting team chose not to include communication requirements between the Generator Owner and TO for the exchange of source impedance data at a given transmission interconnection point, because the standard drafting team is confident this exchange of source impedance data is already occurring outside of Reliability Standard requirements. A communication Requirement for the

Organization	Yes or No	Question 6 Comment
		exchange of source impedance data would be administrative in nature, and would create additional compliance tracking burdens for both entities. No change made.
Luminant Generation Company, LLC	No	Luminant recommends that in the Generator Application section, an example of a generator out-of-step relay application for stable power swings should be provided. **Response:** A generation out-of-step relay example has been added to the Application Guidelines. Change made.
Wisconsin Electric	No	For generators, the Application Guidelines make reference to using the generator transient reactance X'd. However, Tables 15 and 16 show the sub-transient reactance X''d in the calculations. This appears to be a discrepancy. See also Question 3 above. **Response:** The discrepancies in Tables 15 and 16 have been corrected. Change made. See response to Question 3 above.
Kansas City Power & Light	No	The graphs seem not to match the calculations. **Response:** The detailed point calculations for all graphs have been re-checked, and one error was found in Table 17 (E_S/E_R = 1; magnitude should be 0.194 at 201.9 degrees rather than 0.111 at 201.9 degrees.) Change made.
CPS Energy	No	In general, support Luminant comments. **Response:** A generation out-of-step relay example has been added to the Application Guidelines. Change made.
Tacoma Power	No	In the Application Guidelines, in the discussion of Figure 11, suggest changing "...thus allowing the zone 2 element to meet PRC-026-1 - Attachment B, Criteria A" to something like the following: "...thus allowing the zone 2 element to meet PRC-026-1 - Attachment B, Criterion A. However, including the transfer impedance in the calculation of the lens characteristic is not compliant with Requirement R4." Similarly,

Organization	Yes or No	Question 6 Comment
		update the Figure 11 caption to indicate that the calculation is not compliant with Requirement R4. **Response:** The suggested changes have been made. Please note that Requirement R4 is now Requirement R2. In the Application Guidelines, in the discussion of Requirement R5, the statement "that all actions associated with any Corrective Action Plan (CAP) developed in the previous requirement [Requirement R4]..." is incorrect. Requirement R4 does not have anything to do with a CAP. **Response:** The lead paragraph was a leftover duplicate from a prior version of the Application Guidelines. This lead paragraph has been removed. Change made.
ITC	No	The R2 example of an island forming is insufficient. Suppose a line includes tapped load and a tapped generator, does this form an island if the line ends trip for a phase fault? R2 Criteria 2 does not exclude this example, therefore it should be discussed in Application Guidelines and Technical Basis. **Response:** Requirements R2 and R3 were removed and their intent (actual events) is now captured in Requirement R2 (previously Requirement R4). The paragraph referring to the formation of an island in the R2 section of the Application Guidelines has been removed. Change made.
Hydro One	No	This section now provides clarity for each of the requirements in the standard. However, for Requirement 4, the "Application Guidelines and Technical Basis," section does not provide direction on how to treat multi-terminal configurations (specifically 3-terminal). Providing guidance on how to approach multi-terminal configuation would be helpful. **Response:** A 3-terminal line example has been added to the Application Guidelines. Change made.

Organization	Yes or No	Question 6 Comment
Lower Colorado River Authority	No	see comments for application guidelines. It would be helpful to include out of step examples for the GO and TO. **Response:** A generation out-of-step relay example has been added to the generation section of the Application Guidelines. A transmission out-of-step trip example is shown in Figure 15 of the Application Guidelines. Change made.
Tri-State Generation and Transmission Association, Inc.	No	The "Exclusion of Time Based Load-Responsive Protective Relays" on p 25 indicates that time delayed Zone 2 and Zone 3 relays are intended to be excluded from this standard. However, many of the figures reference Zone 2 relay compliance or non-compliance; in particular, see Figure 10. That seems to imply that the Zone 2 relays in the example do need to comply with this standard. If we are told that time-delayed relay elements are to be excluded, does this imply that the Zone 2 relay is being used in a directional comparison blocking (DCB) scheme? If so, should that not be clearly identified? (Only Figures 3 and 12 identify the element in question as being a pilot Zone 2, and pilot could refer to may schemes that would not be impacted by extending beyond the defined impedance boundary). Similar to that example would be the use of Zone 2 relay elements to assert permission in a permissive overreaching transfer trip (POTT) scheme. It is likely that Zone 2 relay elements in a POTT scheme could extend beyond the impedance characteristic defined in Attachment B, but the only regions that would result in tripping in less than 15 cycles are the overlapping Zone 2 regions that result in POTT scheme activation, which would most likely be fully contained in the region defined in Attachment B. Tri-State believes that a statement or example clarifying that such a protection system is compliant would be beneficial to applicable entities as well as the compliance monitoring entities. **Response:** The figures have been updated to generically refer to Pilot Zone 2 and Zone 2 impedance characteristics as "mho element characteristics." A clarifying paragraph has also been added discussing the types of "pilot" or communications relay schemes that need to be considered. Change made.

Organization	Yes or No	Question 6 Comment
Consumers Energy Company	No	The revised application guidelines are very helpful, but need to be expanded to include guidance on how to comply with R2 and R3, specifically how Generator Owners and Transmission Owners are expected to determine whether a trip was due to a swing. Given the lack of guidance we have at this point, we feel we are unable to comply with R2 or R3. **Response:** The standard drafting team contends that PRC-026-1 does not require an entity to determine whether an Element tripped due to a power swing. This is accomplished in the revision to Requirement R2 (previously Requirement R4) that when an entity "becomes aware" it would evaluate the relay(s). The identification of a power swing that causes a BES Element trip could be determined through an entity's Protection System analysis process (e.g., PRC-004[25]), event analysis review by the entity, region, or NERC.
Arizona Public Service Co	Yes	
Puget Sound Energy	Yes	
FirstEnergy Corp.	Yes	
Oncor Electric Delivery LLC	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	

[25] Protection System Misoperation Identification and Correction.

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	Yes	
Idaho Power	Yes	
ISO New England	Yes	
Pepco Holdings Inc.	Yes	
Nebraska Public Power District (NPPD)	Yes	
Ameren	Yes	
Texas Reliability Entity	Yes	No comments.
Hydro One	Yes	This section now provides clarity for each of the requirements in the standard. However, for Requirement 4, the "Application Guidelines and Technical Basis," section does not provide direction on how to treat multi-terminal configurations (specifically 3-terminal). Providing guidance on how to approach multi-terminal configuation would be helpful. **Response:** A 3-terminal line example has been added to the Application Guidelines. Change made.
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 6 Comment
Colorado Springs Utilities		No Comments
Exelon Companies		In the guidelines and technical basis section of the standard, a method for evaluating whether a distance element is susceptible or not is given. In the previous guidelines and technical basis, a simpler method of plotting the relay characteristic within the lens drawn at the 120 degree critical angle was also described. This method seems to have been removed from the current draft standard. This method works often for our protection schemes and requires no calculations (it is simpler and less work). The drafting team should consider putting this section back in the guidelines section to show that this method may also be used. **Response:** A method for evaluating distance elements is provided in the Application Guidelines as shown in Figure 5 and Tables 2 – 7. It is a modified, more realistic method than the one presented in Draft 1. The illustration of the lens calculation is now only for a portion of a lens and the interior intersection with the un-equal EMF power swing trajectories. This approach is more realistic, because it accounts for the fact that the generator voltages won't be zero during a power swing. The generator voltages are varied from 0.7 to 1.0 per unit to create a realistic and adequately conservative portion of a lens against which mho circle distance elements are compared to determine their susceptibility to tripping for stable power swings. The evaluation using the portion of a lens is not more work once an application tool has been developed using the formulae in the Application Guidelines. Additional clarifying examples have been included to the Application Guidelines.

7. **The Implementation Plan for the proposed standard has been revised, based on comments, to account for factors such as the initial influx of identified Elements and ongoing burden of entities to identify Elements and re-evaluate Protection Systems. Does the implementation plan provide sufficient time for implementing the standard? If not, please provide a justification for changing the proposed implementation period and for which Requirement.**

Summary Consideration: Over 80 percent of the entities that commented agreed that the Implementation Plan provides sufficient time for implementing the Standard. Several commenters that disagreed with the Implementation Plan noted that 12 months is not sufficient to prepare studies under Requirement R1. The standard drafting team noted that PRC-026-1 is not requiring the preparation of any studies and only requires the use of the most recent assessments according to the Requirements. The following summarizes the comments received starting with the comments that resulted in a change to the Standard and followed by a summary of comments that did not result in a change to the Standard.

There was one significant theme that resulted in a revision to the Standard. Four comments supported by 31 individuals commented that development and implementation of the Corrective Action Plan (CAP) in Draft 2, Requirements R5 and R6 (now Draft 3, Requirements R3 and R4) should have the same implementation time frame as Draft 2, Requirement R4 (now Draft 3, Requirement R2). This is because the development and implementation of the CAP cannot be enforceable when the Requirement that causes the CAP to be developed has yet to be enforceable. The standard drafting team modified the Implementation Plan so that Draft 3, Requirements R2, R3, and R4 (previously Draft 2, Requirements R4, R5, and R6) have the same implementation period.

There one significant and one minor comment did not result in a revision to the Standard. Most significantly, two comments supported by 32 individuals believe the implementation period should be longer due to having to prepare studies. The standard drafting team noted that the preparation of new studies are not required and the Requirements use the most recent assessments. A minor theme, two comments represented by six individuals requested that Requirement R1 be increased from 12 to 24 calendar months. The standard drafting team disagreed because the Requirement relies on the most recent assessment and not the preparation of new studies.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Twelve months is not adequate to prepare for this standard as written. The Drafting Team should change the Implementation Plan to 24 months.

Organization	Yes or No	Question 7 Comment
		The implementation could be improved by adding when the performance of requirement R1 is due. Is the PC supposed to complete its R1 analysis based on the effective date of the Standard 12 months after FERC approval, or 12 months after FERC approves the Standard then the PC has to complete the study for the calendar year? This can be difficult depending on when FERC approves the Standard. We suggest the revision to 24 months and stating that the PC is expected to complete the identification required by R1 in the calendar year that the requirement becomes effective. This removes the concern of what month FERC approves the Standard. **Response:** The Implementation Plan provides sufficient justification for the implementation periods and allows for 12 calendar months for the Planning Coordinator and 36 calendar months for the Generator Owner and Transmission Owner. Requirement R1 must be performed each calendar year (January-December); therefore, the Planning Coordinator must complete its notification of BES generators, transformers, and transmission line Elements to the respective Generator Owner and Transmission Owner by December 31 of each calendar year. The Implementation Plan states that the Planning Coordinator will begin its performance on the first day of a calendar year 12 calendar months following adoption or approval of the standard. For example, if the standard is approved on September 17, 2015 the 12 calendar month clock starts on the first of the following year (2016); therefore, the year in which the Planning Coordinator must be compliant with the standard will be January 1, 2017. No change made.
ISO RTO Council Standards Review Committee	No	The SRC notes that twelve (12) months is not adequate to prepare for this standard as written. Accordingly, it is recommended that the drafting team revise the implementation plan to allow twenty four months for implementation. **Response:** The standard drafting team has provided additional information in the Implementation Plan document to clarify when certain activities must be implemented. Change made.

Organization	Yes or No	Question 7 Comment
Florida Municipal Power Agency	No	The Implementation Plan does not offer compelling evidence that the implementation date for R5 and R6, which are driven exclusively by R4, should be set at 12 months from approval while R4 is at 36 months from approval. Setting R5 and R6 earlier than R4 instead of allowing them to be parallel to R4 introduces circuitous logic as now the language of these Requirements appears to require R4 to be completed early...There does not appear to be any value in setting R5 and R6 at 12 months when there is nothing to measure compliance with them against - the implementation plan explains the 12 months to is to allow entities to develop “internal processes and procedures”, but the Requirements do not require such procedures nor are these listed in the measures. **Response:** The standard drafting team has modified the Implementation Plan so that Requirements R3 and R4 (previously Requirements R5 and R6) have the same implementation period of R2 (previously Requirement R4). Change made.
SPP Standards Review Group	No	We have a concern that the Implementation Plan doesn’t reflect the changes mentioned by the drafting team in their response to our comments on Question 4 in the previous posting. That response states ‘The drafting team increased the Implementation Plan to three years to provide for the initial influx of identified Elements under Requirement R1. The evaluation of relays under Requirement R4 previously R3) is to be performed “within 12 full calendar months of receiving notification of an Element... where the evaluation has not been performed in the last three calendar years.” Change made’. We request clarification on why this change doesn’t appear in the current proposed standard and Implementation Plan. **Response:** The standard drafting team notes that the reference to “changes made” in the previous posting related to the changes made to the Implementation Plan. In response to additional time for Requirement R1, the standard drafting team notes that studies are not required by the standard (i.e., Requirement R1). The criteria in Requirement R1 are based on existing studies (i.e., annual Planning Assessments) and that the Planning Coordinator will have minimal effort to notify the respective Generator

Organization	Yes or No	Question 7 Comment
		Owner and Transmission Owner of Elements that meet the Requirement R1 criteria. No change made.
ACES Standards Collaborators	No	We do believe the 36-month period of implementation for R4 is sufficient. However, we do not understand why R5 and R6 do not have the same effective date as R4. They are dependent on R4 with the "pursuant to Requirement R4" and "pursuant to Requirement R5" clauses in the requirements. To avoid the confusion associated with monitoring compliance to R5 and R6 when they cannot technically be violated, please align the effective date for R5 and R6 to R4 to avoid this confusion. **Response:** The standard drafting team has modified the Implementation Plan so that Requirements R3 and R4 (previously Requirements R5 and R6) have the same implementation period of R2 (previously Requirement R4). Change made.
ISO New England	No	Twelve months is not adequate to prepare for this standard as written. The drafting team should change the implementation plan to twenty four months. **Response:** The standard drafting team contends that a 36 calendar month implementation of Requirement R4 (now Requirement R2) provides ample time for entities to address the initial influx of identified Elements, if any. Entities should keep in mind that, for example, that Requirement R4 (now Requirement R2) allows a 12 calendar month period to evaluate load-responsive protective relays on the Element which means the entity will have nearly 48 months for completion depending on identification of the Element. No change made.
NIPSCO	No	We would prefer that the 12 month implementation plan for R1-R3, R5, R6 be set to 24 months; this is based on the related burden of implementing PRC-025-1. **Response:** The standard drafting team has modified the Implementation Plan so that Requirements R3 and R4 (previously Requirements R5 and R6) have the same implementation period of R2 (previously Requirement R4). Change made.

Organization	Yes or No	Question 7 Comment
Arizona Public Service Co	Yes	
Puget Sound Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Colorado Springs Utilities	Yes	
Duke Energy	Yes	
Dominion	Yes	If R4 is a precursor for R5 and R6, R4-R6 should be included in the 36 month implementation plan. **Response:** The standard drafting team has modified the Implementation Plan so that Requirements R3 and R4 (previously Requirements R5 and R6) have the same implementation period of R2 (previously Requirement R4). Change made.
DTE Electric Co.	Yes	No comment

Organization	Yes or No	Question 7 Comment
FirstEnergy Corp.	Yes	
Oncor Electric Delivery LLC	Yes	
Public Service Enterprise Group	Yes	
Entergy Services, Inc.	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Luminant Generation Company, LLC	Yes	
City of Tallahassee	Yes	
Idaho Power	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc.	Yes	The 36 month time line is sufficient **Response:** The standard drafting team thanks you for your comment.
CPS Energy	Yes	

Organization	Yes or No	Question 7 Comment
Nebraska Public Power District (NPPD)	Yes	
Tacoma Power	Yes	
Ameren	Yes	
ITC	Yes	
Texas Reliability Entity	Yes	No comments.
Hydro One	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
Lower Colorado River Authority	Yes	
American Transmission Company, LLC	Yes	
Georgia Transmission Corporation	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

Organization	Yes or No	Question 7 Comment
Consumers Energy Company	Yes	
Bonneville Power Administration		BPA cannot estimate if the implementation plan provides sufficient time until BPA determines how many elements that R1 applies to. **Response:** The standard drafting team contends that a 36 calendar month implementation of Requirement R4 (now Requirement R2) provides ample time for entities to address the initial influx of identified Elements, if any. Entities should keep in mind that, for example, that Requirement R4 (now Requirement R2) allows a 12 calendar month period to evaluate load-responsive protective relays on the Element which means the entity will have nearly 48 months for completion depending on identification of the Element. No change made.

8. If you have any other comments on PRC-026-1 that have not been stated above, please provide them here:

Summary Consideration: The following summarizes all other comments received starting with the comments that resulted in a change to the Standard and followed by a summary of comments that did not result in a change to the Standard. Comments summarized in Questions 1-7 are not summarized in this section. See the summaries to the first seven questions.

There were two minor themes of comments that resulted in a revision to the Standard. First, one comment supported by 14 individuals expressed concern about the use of "Elements" rather than "Facilities." The standard drafting team modified the language in the Applicability section and Draft 3, Requirements R1 and R2 to more clearly note "generator, transformer, and transmission line BES Elements to resolve the concern between the two terms defined in the *Glossary of Terms Used in NERC Reliability Standards*. Also, one comment supported by 14 individuals revealed that Draft 2, Requirement R4 (now Draft 3, Requirement R2) was not clear as to what "meets" the PRC-026-1 – Attachment B criteria. The standard drafting team revised the text in PRC-026-1 – Attachment B, Criterion A to clarify that an impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region. Draft 3, Requirement R2 (previously Draft 2, Requirement R4) was revised to evaluate and "to determine whether" relays meet the criteria.

There was on significant and two minor themes of comments that did not result in a revision to the Standard. The significant theme included three comments represented by 47 individuals which suggested changes that are inconsistent with the NERC style for writing; therefore, the suggested changes were not implemented.

The first minor theme included one comment supported by 24 individuals that pointed out that PRC-026-1 leaves out the use of transfer limits to correct for stable power swings. The standard drafting team notes that transfer limits are an important tool in the operation of the BES and are a form of operating limits, but not applicable to the Standard. The PRC-026-1 standard is addressing the risk from a planning standpoint regarding System Operating Limits (SOL) and actual events where the Generator Owner and Transmission Owner becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Second, one comment represented by 14 individuals commented that it is possible for protective relays applied on a substation bus section or on a FACTS[26] device to be susceptible to power swings, and in fact, in cases of intentional system separation schemes, this may be an intentional design (e.g., splitting a substation bus when one or a group of transmission lines exceed a measured condition). The standard drafting team investigated this concern with a few entities and determined there was not a concern that

[26] Flexiable AC Transmission System

would lead to these Elements being added to the Standard's Applicability. Also, these devices were not suggested as applicable Elements in the PSRPS Report,[27] which recommended an approach to a Reliability Standard.

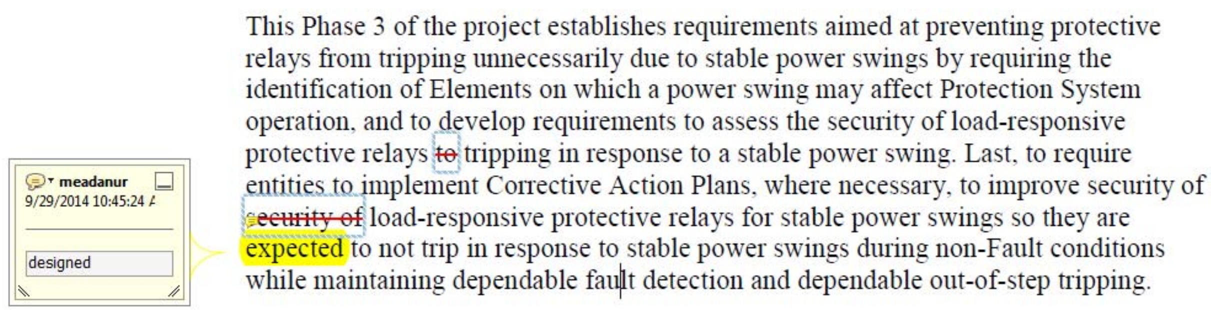
Organization	Question 8 Comment
Northeast Power Coordinating Council	The wording of the Purpose should not have been changed. The existing wording" do not trip" is definitive; the proposed wording "...are expected to..." leaves room for questioning. If the proposed wording is kept, suggest that the Purpose read: To ensure that load-responsive protective relays are not expected to trip in response to stable power swings during non-Fault conditions. **Response:** The standard drafting team phrased the purpose statement to "expected to 'not' trip" because the expectation is that relays "not trip" in response to a power swing. No change made. Regarding requirements R1, R2 and R3, to be consistent with the format of other NERC standards, the Criteria/Criterion listings should be made Parts of requirements R1, R2 and R3. **Response:** The standard drafting team contends that Requirement R1 is written in a clear manner to provide the criterion for which the Planning Coordinator must identify certain Elements to be notified to the respective Generator Owner and Transmission Owner. No change made. The standard drafting team removed Requirements R2 and R3. Change made. Requirement R1 has the Planning Coordinator notifying the respective Generator Owner and Transmission Owner but a specific time period to complete the notification following the identification of an Element is not specified. This may appear as a gap in the process. The Planning Coordinator should have 30 days to notify the TO and GO. **Response:** The standard drafting team contends that it is sufficient for the Planning Coordinator to notify the respective Generator Owner and Transmission Owner on a calendar-year basis. Notification

[27] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Question 8 Comment
	is at the discretion of the PC based on when it identifies Elements, if any, according to the most recent annual Planning Assessment. Based on the time horizons of the Requirements and the objectives of the standard, adding a specified time frame to complete the notification adds no reliability benefit. No change made. PRC-026 leaves out the use of transfer limits to correct for stable power swings. Transfer limits are an important tool for use in power system operations, and should be mentioned in a Rationale Box. **Response:** The standard drafting team notes that transfer limits are an important tool in the operation of the Bulk Electric System and are a form of operating limits. The PRC-026-1 standard is addressing the risk from a planning standpoint regarding System Operating Limits (SOL) and actual events where the Generator Owner and Transmission Owner become aware of a stable or unstable power swing that trips an Element. Entities should not be exempted from the standard because of the linkage to Attachment A. Attachment A should not exclude Relay elements supervised by power swing blocking. Entities may install out of step blocking in order to be exempted from the standard. An entity may install Out of Step Blocking equipment without validating that it is set correctly because PRC-026 would not apply. **Response:** The standard drafting team contends that the installation of power swing blocking relays is an effective means to prevent tripping for stable power swings. The drafting team contends that entities that implement power swing blocking (PSB) relays would do so using engineering judgment and accepted industry practices. A discussion of PSB is in the Application Guidelines. No change made. Measure M3 is missing the word “meet”. Measure M3 should read: M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which meet the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets. **Response:** This Measure was deleted; therefore, eliminated the error. Change made.
Arizona Public Service Co	The 30 days notification requirements for R2 and R3 is unnecessarily too stringent. We suggest 90 days.

Organization	Question 8 Comment
	Response: The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	The NERC SPCS report, Protection System Response to Power Swings (dated August 2013), recommended that NERC reliability standard to address relay performance during stable swings is not needed, and could result in unintended adverse impacts to Bulk-Power System reliability. This report also noted that relay tripping on stable power swings were not casual or contributory in any of the historical events reviewed. According to report it appears that SPCS team did get an input from SAMS team and other industry experts before arriving to the conclusion. So, there is no need of this standard. **Response:** The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[28] in the introductory remarks regarding the need for a standard to meet regulatory directives. The calculation criteria in Attachment B, reduces the probability of relay tripping for stable swings but is not completely fool proof. The swing characteristics vary a lot based on system conditions, such as, system load, topology, generation status and amount of generation etc. So, it is proposed that the relay settings are reviewed and modified as needed by PC or TP based on transient stability analysis instead of setting them based on criteria in attachment B. **Response:** The Attachment B criteria provides a consistent and conservative method for determining a relay's susceptibility to tripping for stable power swings. Requiring Planning Coordinators or Transmission Planners to run additional stability studies to determine a relay's susceptibility to tripping for a stable power swing will be more time consuming than applying the Criteria in Attachment B. Further, the contingencies assessed may not be severe enough to adequately ascertain a relay's susceptibility to tripping for a stable power swing. The option to use an angle less than 120 degrees where a documented transient stability analysis demonstrates the expected maximum stable separation angle is less than 120 degrees is intended to

[28] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Question 8 Comment
	allow entities to reduce the separation angle where it is supported by a transient stability analysis. No change made. Editorial comments: Comments for PRC-026-1 1. Page 5 – Background Section[29]  This Phase 3 of the project establishes requirements aimed at preventing protective relays from tripping unnecessarily due to stable power swings by requiring the identification of Elements on which a power swing may affect Protection System operation, and to develop requirements to assess the security of load-responsive protective relays ~~to~~ tripping in response to a stable power swing. Last, to require entities to implement Corrective Action Plans, where necessary, to improve security of ~~security of~~ load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping. **Response:** Correction made. Comments for Application Guidelines 1. Page 1 - "The development of this standard implements the majority of the approaches suggested by the report." **Response:** Correction made, added "es" to approach. 2. Page 6 - "The standard does not included any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs." **Response:** The standard drafting team chose not to include communication requirements between the Generator Owner and Transmission Owner for the exchange of source impedance data at a given transmission interconnection point, because the standard drafting team is confident this exchange of

[29] The graphic and the text above the graph were appended to the stakeholder's comment original comment due to a technical problem with the electronic submittal.

Organization	Question 8 Comment
	source impedance data is already occurring outside of Reliability Standard requirements. A communication Requirement for the exchange of source impedance data would be administrative in nature, and would create additional compliance tracking burdens for both entities. No change made. 3. Page 8 - "In order to establish a time delay that strikes a line between a high-risk..." What is meant by "strikes"? **Response:** The SDT revised the language in this sentence removing the word "strikes". It now reads "In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1." Change made. 4. Page 8 - "For a relay impedance characteristic that has the swing entering and leaving beginning at 90 degrees with a termination at 120 degrees before exiting the zone..." "Add degrees" **Response:** Addition made. 5. Page 9 - Title of "Application to Transmission Elements", should be "Application Specific to Criteria A". **Response:** Thank you for suggestion; however, the standard drafting team prefers to leave the heading as is. 6. Page 9 - reference Fig 13 and 14 when discussing "infeed effect" **Response:** Added reference to Figures 13 and 14 at the end of the "infeed-effect" text under "Application to Transmission Elements." 7. Figure 3 - Update text box "Constant Angle...Boundary (120 degrees)". Response: The standard drafting team was unable to determine the change needed. 8. Table 2 through 7 - Do not need to calculate each point, does not provide added value to the document. **Response:** Thank you for comment. The standard drafting team considered other approaches to reduce the redundancy of the calculations. For example, having the six points in a six column table, but the

Organization	Question 8 Comment
	font became too small for readability. Six points are considered the critical points to which an entity would need to calculate the lens characteristic. 9. There are many tables and figures not referenced in the written portion of the document which makes the guideline difficult to read and follow. This is the case for Figure 13, 14, 15, and almost all the tables. **Response:** Several of the Tables and Figures are standalone by design and where a figure is used in discussion, it is referenced.
ISO RTO Council Standards Review Committee	The SRC respectfully submits that the Purpose statement is unclear and inconsistent with the requirements in the standard. More specifically, the requirements often refer to stable and unstable power swings, but such are not addressed in the Purpose statement. This should be clarified. The following revision is proposed. To protect against tripping by load-responsive protective relays in response to stable and unstable power swings during non-Fault conditions. **Response:** The standard drafting team believes the Purpose Statement appropriately captures the intent of the standard according to the directives the standard is responding to in the FERC Order No. 733. It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard. The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused

Organization	Question 8 Comment
	approach is based on the PSRPS Report,[30] recommending "…lines that have tripped due to power swings during system disturbances…" as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made. The SRC has concerns with potential inconsistency between the Purpose statement and the time horizons. Specifically, Requirements R2 and R3 have a time horizon defined as Long Term Planning while the Purpose of the standard is about expected / forecasted responses. However, the verbiage of Requirements R2 and R3 requires action by the responsible entities within 30 days, which implies that the Time Horizon should be, at most, the Operations Planning time frame. The SRC requests that the SDT to review these requirements to assure they are consistent with the purpose of the standard, the Time Horizons and any changes necessary to the Applicability section. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made.
Dominion	No part of the standard discusses reasonable slip frequencies that should be used to detect power swings. If we identify a relay that is susceptible to tripping for stable power swings (based on the mho impedance characteristic overlapping a portion of the lens), apply a form of power swing blocking, and then the relay operates again for a different frequency. Are we to go off the most recent analysis? Slip frequency is an integral part to power swing detection and determination between a swing and loading can be difficult. There should be some discussion about this topic in conjunction with loading. Should a section discuss the correlation with PRC-023-2 requirement R2?

[30] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Question 8 Comment
	PRC-023-2 R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. **Response:** The standard drafting team notes that the use of slip frequencies in the setting of power swing blocking relay(s) is outside the scope of the standard. No change made.
DTE Electric Co.	Will this Standard result in any conflicts with PRC-019 or PRC-025 while meeting protection goals in setting generator relays? **Response:** The standard drafting team is unaware of any conflicts.
ACES Standards Collaborators	(1) We believe the data retention section is inconsistent with the RAI. RAI is intended to refocus the ERO's compliance monitoring and enforcement efforts on those matters that pose the greatest risk to the reliability to the BES. This involves making compliance monitoring and enforcement forward looking to provide reasonable assurance of future compliance and reliability. How does a three-year data retention requirement support this forward looking vision of RAI? We suggest that the data retention should be no more than one year, based on the annual cycle established in this standard. **Response:** The standard drafting team has revised the minimum periods to retain evidence to 12 calendar months in the Evidence Retention section to address Risk Assurance Initiative (RAI) concerns. Change made. (2) Why is 36 calendar months in bullet 4 instead of 3 calendar years that is used in the first three bullets? It seems they should be the same to avoid confusion. Notwithstanding our earlier comments regarding making the data retention period no longer than one year, we suggest using consistent language throughout the data retention section. Thus, use either 36 calendar months or three calendar years, but not both. **Response:** The standard drafting team has revised the minimum periods to retain evidence to 12 calendar months in the Evidence Retention section to address Risk Assurance Initiative (RAI) concerns. Change made.

Organization	Question 8 Comment
Bonneville Power Administration	BPA suggests re-ordering the requirements for continuity because the standard is working/designing the system to prevent trips by load-responsive relays unnecessarily. R1 (PC identify criteria influenced Elements ANNUALLY) R4 (GO/TO evaluate elements identified by the PC's identifier of Gen restraint, line part of SOL angular, UFLS line boundary)R5 (GO/TO develop a CAP for at risk protection on R4 elements) R6 (GO/TO implement the CAP) R2 (TO notify PC within 30 days if an element trips by load-responsive protection due to swings or forms a boundary during a actual system Disturbance) R3 (GO notifies PC within 30 days if element trips by load-responsive protection during a swing) **Response:** The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made.
Entergy Services, Inc.	Based on the information contained in the SPCS Power Swing Report Dated August 2013, there is insufficient evidence in the historical study case identified, to warrant implementation of the proposed PRC-026-1 standard. **Response:** The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[31] in the introductory remarks regarding the need for a standard to meet regulatory directives.
Lincoln Electric System	Although aware of the forces driving the development of PRC-026-1, LES cannot support the standard. LES agrees with the statement in the NERC System Protection and Control Subcommittee's technical report titled "Protection System Response to Power Swings" that recommends against this standard. Reliability Standards PRC-023-3 and PRC-025-1 adequately ensure that load-responsive protective

[31] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Question 8 Comment
	relays will not trip in response to stable power swings during non-Fault conditions. Additionally, as stated in this same report, consideration should be given to potential adverse impacts to Bulk Power System reliability as a result of the standard. **Response:** The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[32] in the introductory remarks regarding the need for a standard to meet regulatory directives.
Xcel Energy	We believe there is insufficient technical basis to make this a viable standard for industry to properly apply, and provide the following comments for consideration: We concur with the NERC concern noted in #133 of FERC order 733 that careful study and analysis of the relationship between stable power swings and protective relays is needed and consultation with IEEE and other organizations should be completed before developing a Reliability Standard addressing stable power swings. The need basis for this standard is 2003 blackout event data. Since that time, many improvements to protection systems have occurred, voltage control and frequency control requirements have either been implemented, are on a staged implementation plan, or are planned in the immediate future. The need basis data set has changed and should be based on current information, rather than past uncontrolled system reliability program data. Many improvements over the last 11 years have changed the probability of this particular need occurring, including: o Use of Generator AVR and PSS systems o Improved facility equipment ratings o Automatic voltage and frequency ride-through standards for wind turbines o Coordinated protection system settings amongst all players o Better system modeling and transmission planning These concerns would be addressed by a carefully planned study as described.

[32] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Question 8 Comment
	We are aware of FERC's concerns around undesirable operations due to stable power swings, per Orders 733, 733A and 733B. The directive in #150 states "...we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement." We are also aware that this requirement was reinforced on September 4th, in the applicable FERC staff meeting. Due to the real or perceived urgency in completing this standard, we have offered some proposed wording intended to expedite the acceptance of the regulation. As written, we believe this draft holds potential opportunities for improvements towards readability and cohesiveness. **Response:** The standard drafting team thanks you for your comment and provided a detailed explanation in the previous Consideration of Comments[33] in the introductory remarks regarding the need for a standard to meet regulatory directives.
Idaho Power	The 30 day time requirement for notification of swing tripping events in R2 and R3 seems a little short. I think 45 to 60 days would be more appropriate. **Response:** The standard drafting team thanks you for your comment and notes that Requirements R2 and R3 have been removed and changes were made to the previous R4 (now Requirement R2) to address other comments and concerns. Change made.
ISO New England	PRC-026 leaves out the use of transfer limits to correct for stable power swings. Transfer limits are an important tool for use in power system operations. **Response:** The standard drafting team notes that transfer limits are an important tool in the operation of the Bulk Electric System and are a form of operating limits. The PRC-026-1 standard is addressing the risk from a planning standpoint regarding System Operating Limits (SOL) and actual events where the Generator Owner and Transmission Owner become aware of a stable or unstable power swing that trips an Element.

[33] http://www.nerc.com/pa/Stand/Project%202010133%20Phase%203%20of%20Relay%20Loadability%20stabl/Project_2010_13.3_Consideration_of_Comments_2014_08_22_to_Draft_1.pdf

Organization	Question 8 Comment
	Furthermore, Attachment A should not exclude Relay elements supervised by power swing blocking. Entities might simply install out of step blocking in order to be effectively exempted from the standard. An entity could just install Out of Step Blocking equipment with nothing to ensure that it is set correctly and the standard would not apply through the exclusion in Attachment A. This will not improve power system reliability. **Response:** The standard drafting team contends that the installation of power swing blocking relays is an effective means to prevent tripping for stable power swings. The drafting team contends that entities that implement power swing blocking (PSB) relays would do so using engineering judgment and accepted industry practices. A discussion of PSB is in the Application Guidelines. No change made.
Nebraska Public Power District (NPPD)	We are curious why the PC is allowed 1 year to identify elements while the industry is allowed 30 days after a disturbance to identify elements. This does not seem practical in comparison with the timelines used with other reporting requirements. For example, PRC-004 has quarterly submissions with 2 additional months after the quarter end; the new PRC-004-3 allows 120 days just to identify if an operation was a misoperation, root cause determination is not included in that timeframe. In fact, PRC-004-3 includes no set timeline to determine cause, simply a requirement to actively investigate by indicating active investigation every two calendar quarters until a cause is determined or no cause can be found. An out-of-step analysis is more complex, so it would be logical to allow longer time horizons for this type of investigation and identification, perhaps no less than an annual interval which would match the PC. **Response:** The standard drafting team contends that PRC-026-1 does not require an entity to determine whether an Element tripped due to a power swing. This is accomplished in the revision to Requirement R2 (previously Requirement R4) that when an entity "becomes aware" it would evaluate the relay(s). The identification of a power swing that causes a BES Element trip could be determined through an entity's Protection System analysis process (e.g., PRC-004[34]), event analysis review by the entity, region, or NERC. Additional clarification on two items is requested:

[34] Protection System Misoperation Identification and Correction.

Organization	Question 8 Comment
	1) If a relay has out of step tripping and blocking enabled, does this mean it is excluded from the standard? **Response:** The standard drafting team notes that out-of-step trip relaying must still comply with the criteria in Attachment B of the standard. 2) If a relay has out of step blocking enabled, does this mean it is excluded from the standard? **Response:** The standard drafting team notes that relay elements that are supervised by power swing blocking are excluded from the Requirements of this standard based on Attachment A. In addition to these comments, we support the comments provided by SPP. **Response:** The standard drafting team thanks you for your comments, please see response to SPP Standards Review Group.
Tacoma Power	For Requirement R2, consider defining 'island' or adding a footnote clarifying the intent of the word. This requirement should not apply to portions of the system containing both generation and load that become isolated from the BES but that are not intended to operate apart from the BES. For example, perhaps there are parallel lines that interconnect one or more remote generation plants and some load to the rest of the system. It is doubtful that the drafting team intended to include these types of scenarios as 'islands'. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made. Should POTT and DCB schemes be specifically called out in Attachment A as being applicable to PRC-026-1? **Response:** The figures have been updated to generically refer to Pilot Zone 2 and Zone 2 impedance characteristics as "mho element characteristics." A clarifying paragraph has also been added to the Guidelines and Technical Basis under the Requirement R2 heading which discusses the types of "pilot" or communications relay schemes that need to be considered. Change made.

Organization	Question 8 Comment
	Attachment B Criterion B may yield current that is above the phase time overcurrent pickup but, at this level of current, the phase time overcurrent element may take longer than 15 cycles to operate. Therefore, the approach in Attachment B Criterion B is potentially conservative. **Response:** The standard drafting team thanks you for your comment. The Response to Issues and Directives still mentions that "...the proposed standard does require that an Element that was part of a boundary that formed an island since January 1, 2003 be identified as an that is within the scope of the proposed standard."
Ameren	We appreciate the SDT's significant improvements in this draft 2. Our response to question 3 above captures our primary reason for voting negative. **Response:** Correction made.
ITC	In R2, add reference to Attachment A when describing the load-responsive protective relays. R2 Criteria 2 adds no value and should be removed. All Elements which trip due to swings will be captured under Criteria 1. Criteria 2 only includes islands formed due to phase faults and adds no value. If you intend to capture boundaries of all islands formed, then remove the "due to the operation of its load-responsive protective relays" qualifier. If you intend to capture boundaries of all islands formed due to protective relay operations, then remove the "load-responsive" qualifier. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made. Application Guidelines, page 63, Application to Generation Elements, change the language to include generator relays, if they are set based on equipment permissible overload capability. "Load-responsive protective relays such as time over-current, voltage controlled time-overcurrent or voltage-restrained time-overcurrent relays are excluded from this standard [if] they are set based on equipment permissible overload capability." **Response:** Correction made.

Organization	Question 8 Comment
	Application Guidelines, page 72, the first paragraph under Requirement R5 is more appropriate under Requirement R6. **Response:** The standard drafting team eliminated the text.
Texas Reliability Entity	Texas RE suggests that the PRC-026-1 SDT refer this standard to the Project 2014-01 SDT (if not done already) for consideration regarding the applicability of BES generators to include dispersed generation resources so the requirements of the standard pertain primarily to the point of connection where the resources aggregate to 75 MVA or more, and not to the individual resources. Since this is a new standard it is not currently included in “Appendix B: List of Standards Recommended for Further Review” from the draft white paper entitled “Proposed Revisions to the Applicability of NERC Reliability Standards NERC Standards Applicability to Dispersed Generation Resources.” **Response:** The standard drafting team has been coordinating with the dispersed generation resources project team. No conflicts have been identifies.
CenterPoint Energy	CenterPoint Energy recommends removing references to “unstable” power swings in the draft PRC-026-1 standard, as we believe tripping from unstable power swings is random and not indicative of an Element being more susceptible to a stable power swing. Where tripping actually occurs for an unstable power swing is dependent on the location and nature of the event, system conditions, and where additional Element outages occur during a disturbance. We are not aware of any available technical information or analysis to justify that an Element is more susceptible to a stable power swing if it has tripped from an unstable power swing. **Response:** It is important to note that this standard does not require that entities assess Protection System performance during unstable swings and does not require entities to prevent tripping in response to unstable swings. Such requirements would exceed the directive stated in the Federal Energy Regulatory Commission (FERC) Order No. 733. This standard focuses on the identification of Elements by the Planning Coordinator (Requirement R1) and Elements where the Generator Owner or Transmission Owner becomes aware of an Element that tripped in response to a stable or unstable power swing (Draft 3, Requirement R2, 2nd bullet). Requirement R1 and R2 (2nd bullet) is a screen to identify Elements that are subject to the Requirements of the standard.

Organization	Question 8 Comment
	The FERC Order No. 733 directive is perceived as broad and overreaching and could require all relays to be capable of differentiating between stable power swings and faults. This standard's focused approach is based on the PSRPS Report,[35] recommending "...lines that have tripped due to power swings during system disturbances..." as one of the ways to focus the evaluation. Based on feedback from the contributors to the PSRPS Report, that recommendation does not exclude unstable power swings. Furthermore, it is reasonable to assume that an Element that experiences an unstable swing (in either a simulation or reality) is likely to experience large stable power swings for less severe disturbances (that are probably more likely to occur). Thus, the standard drafting team concluded that addressing Protection Systems for Elements that tripped due to unstable power swings provides a reliability benefit. No change made.
Duke Energy	Duke Energy agrees in part with the revisions made by the SDT on this project. However, due to the amount of technical information provided in the Application and Guidelines portion of this standard, more time is needed for our SME(s) to thoroughly review this section before submitting an "Affirmative" vote. **Response:** The standard drafting team thanks you for your comment.
Florida Municipal Power Agency	FMPA would like to commend the SDT for developing an overall process that is generally reasonable and does not, in our opinion, add an excessive compliance burden, since the number of identified circuits and generators should be small. However, we believe more work is required to make the concept the SDT has come up with successful. 1. First, as mentioned in earlier sections, the standard is in general written with the perspective of large vertically integrated utilities in mind, and does not consider the impact on non-vertically integrated TOs and GOs. As such, we believe there is further coordination that needs to be developed between this standard and PRC-004, that will

[35] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Question 8 Comment
	a) facilitate communication between PCs, TPs, TOPs, the RC, and respective investigating TOs and GOs and b) will establish a clear timeline that can cleanly be audited for R2 and R3. As stated in our comments above on R2, the requirements for keeping records for “correct” relay operations are effectively non-existent in current standards. FMPA believes it makes sense for all “investigations” and associated records to occur within PRC-004 and then for “power swing” related activities to occur in PRC-026. Currently power swings are only discussed in PRC-004 as they relate to failure to trip or slow trip conditions (and not where operation for a power swing was correct). Furthermore there is presently no acknowledgment that GOs and TOs may need assistance and information from their TPs, PCs, associated TOP, or even RC. **Response:** The standard drafting team contends that PRC-026-1 does not require an entity to determine whether an Element tripped due to a power swing. This is accomplished in the revision to Requirement R2 (previously Requirement R4) that when an entity “becomes aware” it would evaluate the relay(s). The identification of a power swing that causes a BES Element trip could be determined through an entity’s Protection System analysis process (e.g., PRC-004[36]), event analysis review by the entity, region, or NERC. There is no requirement to track “correct” operations now that Requirement R2 (previously Requirement R4) is triggered on becoming aware of a trip that is due to a power swing. The entity would maintain records demonstrating compliance with the Requirement upon becoming aware of the trip. The standard drafting team chose not to include communication requirements between the Generator Owner and Transmission Owner for the exchange of source impedance data at a given transmission interconnection point, because the standard drafting team is confident this exchange of source impedance data is already occurring outside of Reliability Standard requirements. A communication Requirement for the exchange of source impedance data would be administrative in nature, and would create additional compliance tracking burdens for both entities. No change made.

[36] Protection System Misoperation Identification and Correction.

Organization	Question 8 Comment
	2. The Applicability section refers to GO's and TO's that apply load responsive relays to Generators, Transformers, and Transmission Lines. FMPA sees three issues related to this. a. First, all language in the standard Requirements refers to Elements instead of Facilities - based on previous comments and the SDT's response to those comments, the standard Requirements should be referring to Facilities to draw focus to the BES distinction, which does not exist for Elements. **Response:** The standard drafting team has modified the language in the Applicability section and Requirements R1 and R2 (previously Requirement R4) to more clearly note "BES generator, transformer, and transmission line Elements. Change made. b. Second, the identification of issues and tracking of issues from entity to entity is based on Elements. This works from the perspective of identification of risks to the system but falls short when it comes time to evaluate and modify the Protection Systems, because no Requirement refers back to the Owner of the Protection Systems applied on the Elements identified in R1. Instead, Requirements 2 and 3 are directed at the Owner of the Element itself which may or may not own the Protection System that is actually at risk of operating (or misoperating). The Requirements need to consider this relationship similar to PRC-004-3. **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made. c. Third, it is quite possible for protective relays applied on a substation bus section or on FACTS devices to be susceptible to power swings, and in fact, in cases of intentional system separation schemes, this may be an intentional design (e.g splitting a substation bus when one or a group of transmission lines exceed a measured condition). The Facilities section does not include such Elements. **Response:** The standard drafting team notes that these devices are not suggested as applicable Elements in the PSRPS Report[37] which recommended an approach to a Reliability Standard. No change made.

[37] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Organization	Question 8 Comment
	3. FMPA is concerned the conditions under which Criteria A is being calculated may be excessively conservative. Item 3 of the Criteria states “Saturated (transient or sub-transient) reactance is used for all machines.” Note the term “all”, which could be confusing if an entity is not considering the context. The documentation presented does not discuss terms such as “maximum generation dispatch” or any other term that would relate back to a realistic number of generators being in service. The requirement should be “all machines that are in service in short circuit model”, and in the Application Guide there should be some discussion on using maximum reasonable generation dispatches in short circuit cases. Similarly, but of less consequence, it is not clear that the Transfer Impedance should always be completely neglected. While this is certainly numerically convenient, FMPA wonders if this does not produce overly conservative results in cases of well-networked transmission. Would it not be more prudent to remove other transmission circuits which have significant transfer distribution factors relative to the line in question, and then re-calculate the transfer impedance, rather than assuming some exceedingly large number of transmission outages has occurred? This relates to the comment above that some discussion should be offered surrounding Table 10 in the Application Guide. **Response:** The standard drafting team contends that the Attachment B criteria provides a consistent and conservative approach to achieving the intent of the standard. The Guidelines and Technical Basis have additional text regarding the transfer impedance and Table 10. 4. As written, the combination of Requirement R4 (which instructs the TO/GO to “evaluate” its relays against the “Criteria” in Attachment B) and the Criteria in Attachment B, make no definitive statements about what relays “meet” anything, or “are deficient and require corrective action plans” etc. Requirements and Criteria should be very clear and straight forward. The “Criteria” is really just a description. There is no information in the Requirement or in the Attachment that actually involves making a “judgment” which is the most important part of the definition of the term Criteria. FMPA is well aware of the intent of these two items and only wishes to point out that the intent is really only made clear in the Application Guidelines. **Response:** The standard drafting team has revised the text in Attachment B, Criterion A to clarify that an impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region. Requirement R2

Organization	Question 8 Comment
	(previously Requirement R4) was revised to evaluate and "to determine whether" relays meet the criteria. Change made.
SPP Standards Review Group	Delete the reference to PRC-026-1 in 4.1.1 and 4.1.3 in the Applicability section. Leave the references simply as Attachment A. **Response:** The standard drafting team prefers to leave the reference in because it maintains consistency with the other two relay loadability standards (i.e., PRC-023 and PRC-025) and provides an appropriate reference to the attachment is separated from the standard itself. No change made. Delete 'This' in the 1st line of the 4th paragraph under 5. Background:. **Response:** The standard drafting team correction made. At the end of the 6th line and beginning of the 7th line in the same paragraph, delete 'of security'. Response: The standard drafting team correction made. Hyphenate 30-, 60-, 90-calendar days and similar construction with calendar months throughout the standard. **Response:** The standard drafting team notes that the current formatting of days noted above is consistent with the NERC document style guide. No change made. At the end of each of the first three bullets in 1.2 Evidence Retention the phrase 'following the completion of each Requirement' appears. Since each bullet only refers to one requirement what does this phrase mean when applied to Requirements R1, R2 and R3 individually? **Response:** The standard drafting team has replaced "each" with "the" for clarity. Change made. Why is the timing for notification in the VSLs for the Transmission Owner in Requirement R2 and the Generation Owner in Requirement R3 different from that for the Planning Coordinator in Requirement R1? Shouldn't they be the same? **Response:** The standard drafting team removed Requirements R2 and R3; therefore, the issue is no longer present. Change made.

Organization	Question 8 Comment
	We recommend that all changes made to the standard be reflected in the RSAW as well. **Response:** The standard drafting team will provide input to NERC Compliance regarding the RSAW.
City of Tallahassee	This standard will cause a large increase in workload for entities with a small trade off of system reliability. **Response:** The standard drafting team notes that the standard is presenting an equally effective and efficient approach to the Federal Energy Regulatory Commission (FERC) Order No. 733 directive, and is narrowly focused on specific Elements, and reduces the burden to entities when compared to the directive in Order No. 733. See the "Table of Issues and Directives" document in the posting for FERC's original directive. NERC is obligated to respond to FERC's directive.
Exelon Companies	We agree with the drafting teams' decision that only those elements that trip in less than 15 cycles need to be evaluated for susceptibility to tripping during stable power swings. This follows from actual event experience that shows that the vast majority of relays that trip during power swings are zone 1s. **Response:** The standard drafting team thanks you for your support.

END OF REPORT