NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenter's who submitted comments on the 1st draft of the standard for Protection System Coordination for Performance During Faults. These standards were posted for a 45-day public comment period from May 21, 2012 through July 5, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 76 sets of comments, including comments from approximately 198 different people from approximately 139 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:

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Definitions

The drafting team added the following sentence to the standard to specify that the definitions will not be added to the NERC Glossary of Terms. "The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the Glossary of Terms:"

The drafting team modified the previous definition of Interconnected Facilities to 'Interconnected Element' defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."

Purpose

The drafting team modified the purpose statement based on comments related to two main issues: (1) the inclusion of the phrase '…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards', and (2) the inclusion of the phrase '… remove

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

from service only those Elements...'. The purpose now reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.

Applicability
The Applicability was modified as follows:

4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Requirements
The time frame for Requirement R1, Part 1.1.1 was increased to forty-eight calendar months to allow entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies. Additionally, changes were made to not exclude studies performed prior to June 18, 2007. Requirement R1, Part 1.1.1 now reads: (Part 1.1 Perform a Protection System Study)…"Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists."

The drafting team modified Requirement R1, Part 1.1.2 to be consistent with the Fault location referenced in Requirement R2, Parts 2.1 and 2.2 such that it now reads: "Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required."

The drafting team modified Requirement R1, Part 1.1.3 for clarity. It now reads: "According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required."

The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."

The drafting team reworded Requirement R2 to read as follows: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

The drafting team modified Requirement R2, Part 2.1 to provide clarity as to where the Fault should be applied. Requirement R2, Part 2.1.1 now reads: At least once every 24 months: "Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

The equation stated in Requirement R2, Part 2.1.2 was modified to replace "V" with "I".

The drafting team modified Requirement R2, Part 2.2 to provide clarity and to change "notify" to "provide" such that it now reads: "Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element the updated Fault current values (Iscs)."

The drafting team modified Requirement R3 for clarity and moved the examples into Measure M5 such that it now reads: "Acceptable evidence may include, but is not limited, a summary of the future project or technical specifications of the proposed changes (e.g., project schedule, protective relaying scheme types and settings) in hard copy or electronic file formats as identified in the bulleted list for Requirement R3, Part 3.1 was provided to each responsible entity connected to the same Interconnected Element."

The drafting team modified Requirement R3, Part 3.1 for consistency with changes to other requirements, the addition of the examples, combining the second and third bullets, and clarity. It now reads: "Details for any change or additions listed below; either at an existing or new Facility associated with the Interconnected Element; or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

- New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios
- Changes to a transmission system Element that change any sequence or mutual coupling impedance
- Changes to generator unit(s) that result in a change in impedance
- Changes to the generator step-up transformer(s) that result in a change in impedance

The drafting team modified Requirement R3, Part 3.2 for clarity. It now reads: "Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule."

The drafting team combined the Requirement R3 Part 3.3 subparts 3.3.1 and 3.3.2 into the main body of the Requirement R3, part 3.3 which now reads: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."

The drafting team removed the term “confirm agreement” from Requirement R4, Part 4.1 and revised it to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”

The drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”

The drafting team removed Requirement R4, Part 4.3.

Measures
The drafting team modified all the measures to be consistent with the revised requirements.

Evidence Retention
The drafting team modified the language for consistency.

VSLs and Time Horizon
The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the ‘Lower’ VSL was lengthened from 10 days to 30 days.

The drafting team added Long-term Planning to the Time Horizon for Requirement R3.

Guidelines and Technical Basis
Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team added the following to the description of a Protection System Study in the “Guidelines and Technical Basis”: “System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions.”

The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

The drafting team modified the process flow chart to be consistent with the requirements.

Unresolved Minority Views

- Several commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included because those entities were identified as providing the Protection System Studies and/or system modeling services for the owners. An example response to these comments was as follows: The SDT believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.
- Several commenters disagreed with the Distribution Provider being included. The SDT responses indicated that the inclusion of Distribution Providers was appropriate if the Distribution Provider owned Protection Systems that require coordination with other owners for isolating generation and Transmission Faults.
- A few commenters disagreed with the 10% deviation trigger. The drafting team recognizes there are variations of margins used throughout the industry; however, believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.
- A few commenters had concerns with the 30-day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change.
- Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.
- A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.
- Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices. Note that the drafting team changed from agreement to confirm acceptance.
- Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, “The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to

an existing standard or development of a new standard”. Note: PRC-001-1 Requirement 1 never had an associated measure.

- Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.
- A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there is not a single time frame that would be appropriate for every project and chose not to modify the standard.

Index to Questions, Comments, and Responses

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	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool NERC Reliability Standards Development Team	X	X		X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Sean Simpson	Board of Public Utilities of Kansas City, Kansas	SPP	NA

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

4.	Willy Haffecke	City Utilities of Springfield	SPP	1, 4
5.	Fred Ipock	City Utilities of Springfield	SPP	1, 4

3.	Group	Michael Jones	National Grid USA / Niagara Mohawk	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Schiavone	Niagara Mohawk (National Grid)	NPCC	3

4.	Group	David Thorne	Pepco Holdings Inc. & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light	RFC	1
2.	Mark Godfrey	Pepco Holdings	RFC	1
3.	Alvin Depew	Pepco	RFC	1

5.	Group	Sasa Maljukan	Hydro One	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1
2.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1

6.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

7.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2.	Lupe Ontiveros	IID	WECC	1, 3, 4, 5, 6

8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean	Bender	WECC	1
2.	Fran	Halpin	WECC	5
3.	Erika	Doot	WECC	3, 5, 6

9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	L. Raczkowski	FE	RFC	
2.	J. Detweiler	FE	RFC	

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

3.	B. Orians	FE	RFC	
4.	D. Hohlbaugh	FE	RFC	

10.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shawn T. Abrams	Santee Cooper	SERC	1
2.	Bridget Coffman	Santee Cooper	SERC	1
3.	Rene' Free	Santee Cooper		1

11.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Barbara Holland			3, 4, 5
2.	Karie Barczak			3, 4, 5
3.	David Szulczewski			3, 4, 5

12.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Dunckel	Okanogan PUD	WECC	1
2.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
3.	Ronald Sporseen	Central Electric Cooperative	WECC	3
4.	Ronald Sporseen	Consumers Power	WECC	1, 3
5.	Ronald Sporseen	Clearwater Power Company	WECC	3
6.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
7.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
8.	Ronald Sporseen	Northern Lights	WECC	3
9.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
10.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
11.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
13.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
14.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
15.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
16.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
17.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 8
18.	Ronald Sporseen	Power Resources Cooperative	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	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.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid		1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
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.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co.of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6

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

7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
15.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates					X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
2.			WECC	5
3.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
4.			NPCC	6
5.			SERC	6
6.			SPP	6
7.			RFC	6
8.			WECC	6

				1	2	3	4	5	6	7	8	9	10
16.	Group	Joe Spencer	SERC Protection and Control Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andrew Monroe	Georgia Power (So. Co.)	SERC	
2.	Paul Nauert	Ameren	SERC	
3.	Charlie Fink	Entergy	SERC	
4.	Russ Evans	SCANA	SERC	
5.	Steve Edwards	Dominion/Va Power	SERC	
6.	Jay Farrington	PowerSouth	SERC	
7.	John Miller	GTC	SERC	
8.	Ernesto Paon	MEAG Power	SERC	
9.	Phil Winston	Georgia Power (So. Co.)	SERC	
10.	Bridget Coffman	Santee Cooper	SERC	
11.	George Pitts	TVA	SERC	

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

12.	David Greene	SERC	SERC	
13.	Joe Spencer	SERC	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Morland		WECC	1
2.	Charles Morgan		WECC	3
3.	Lisa Rosintoski		WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Charles Yeung	ISO RTO Council SRC		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gary DeShazo	CAISO	WECC	
2.	Steve Myers	ERCOT	ERCOT	
3.	Matt Goldberg	ISONE	NPCC	
4.	Bill Phillips	MISO	MRO	
5.	Greg Campoli	NYISO	NPCC	
6.	Stephanie Monzon	PJM	RFC	
7.	Don Weaver	NBSO	NPCC	
8.	Ken Gardner	AESO	WECC	

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Akens		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Mary Jo Cooper	GP Strategies	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Elizabeth Kirkley	City of Lodi	WECC	3
2.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3
3.	Douglas Dreager	Alameda Municipal Power	WECC	3
4.	Ken Dizes	Salmon River Electric Co-op	WECC	1, 3
5.	Sam Rohn	California Pacific Electric Co.	WECC	3
6.	Colin Murphey	City of Ukiah	WECC	3
7.	Michael Knott	Granite State Electric	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	David Dockery	Associated Electric Cooperative, Inc.,	X		X		X	X				

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
			JRO00088										

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
2.	John Shaver	Arizona Electric Power Cooperative Inc.	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative Inc.	WECC	1
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Group	Tim Hinken	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gammon	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
26.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	John Hagen	Pacific Gas and Electric Company	X		X		X					
29.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Thad Ness	American Electric Power	X		X		X	X				
32.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.				X						
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Martin Kaufman	ExxonMobil Research & Engineering	X		X		X		X			
36.	Individual	Jonathan Meyer	Idaho Power Company	X		X							
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Don Jones	Texas Reliability Entity										X
39.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
40.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
41.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
42.	Individual	Chris Scanlon	Exelon	X		X		X	X				
43.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
44.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
45.	Individual	Bill Middaugh	Tri-State G & T	X									
46.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
47.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
48.	Individual	Kirit Shah	Ameren	X		X		X	X				
49.	Individual	John D. Martinsen	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
50.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP, (Occidental Chemical Corporation)					X					
51.	Individual	John W Miller	Georgia Transmission Corporation	X									
52.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
53.	Individual	Rich Salgo	NV Energy	X		X		X					
54.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
55.	Individual	Mike Weir	Dairyland Power Cooperative	X		X		X					
56.	Individual	Deborah Schaneman	Platte River Power Authority	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
57.	Individual	E Hahn	MWDSC	X									
58.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
59.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
60.	Individual	Rick Koch	Southern Minnesota Municipal Power Agency				X		X				
61.	Individual	Don Schmit	NPPD	X		X		X					
62.	Individual	Brian Evans-Mongeon	Utility Services								X		
63.	Individual	daniel	mason	X				X					
64.	Individual	Rowell Crisostomo	ATCO Electric	X									
65.	Individual	Bob Thomas and Kevin Wagner	Illinois Municipal Electric Agency				X						
66.	Individual	Rhonda Bryant	El Paso Electric Company	X									
67.	Individual	Steven Powell	Trans Bay Cable	X							X		
68.	Individual	Daniela Hammons	CenterPoint Energy	X									
69.	Individual	Laura Lee	Duke Energy	X		X		X	X				
70.	Individual	Jack Stamper	Clark Public Utilities	X									
71.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
72.	Individual	Brian J Murphy	NextEra Energy Inc	X		X		X	X				
73.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
74.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
75.	Individual	Jian Zhang	TransAlta Centralia Generation LLC					X					
76.	Individual	Pablo OÃ±ate	El Paso Electric	X		X		X	X				

1. **The SDT established the following Purpose for this standard: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." Do you agree with this Purpose? If not, please provide specific suggestions for changes to the purpose in the comment area.**

Summary Consideration:

The responses were equally split between yes and no. Many negative comments related to the inclusion of the phrase '… while meeting the system performance specified within requirements established in other approved NERC Reliability Standards'. Several comments related to the phrase '… remove from service only those Elements ...' due to the fact that some designs include multiple elements within a single protection zone such as bank/bus differential schemes. Suggestions included eliminating 'only' or to add 'as designed'. The Purpose has been modified as follows which addresses the large majority of the negative comments.

Purpose: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear faults.

Organization	Yes or No	Question 1 Comment
Dominion	No	1. Dominion supports the stated purpose up to the comma. The qualifying language after the comma is ambiguous and not supported in the Requirements of this standard. 2. In the current PRC-001-1 standard the meaning of the term "coordination" has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between entities. The term "coordination" should be removed from the new standard Title and Purpose. a. Recommend changing **Title** to: <u>"Protection System Interconnected Facility Performance During Faults".</u> Also, recommended is to change the **Purpose** to read<u>: "To communicate and exchange Protection</u>

Organization	Yes or No	Question 1 Comment
		System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults." In PRC- 027-1, use the term coordination only when referring to the technical aspects of the relay coordination within a Requirement when applicable. b. Under **Purpose**, delete: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."** **a. The drafting team agrees that the use of the term "coordination" in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes the use of "coordination" in this standard clearly relates to the technical aspects of relay coordination and respectfully declines to make the suggested changes.** **b. Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Southwest Power Pool NERC Reliability Standards Development Team	No	We would ask that the team revise the second part of the purpose to lead in with "In accordance with the system performance specified within requirements established in other approved NERC Reliability Standards" If

Organization	Yes or No	Question 1 Comment
		left as is it reads like you are required to do both the first and second parts of the purpose. This proposed language requires the initial goal of this standard and references that it will do so under the system performance specified in NERC standards.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Pepco Holdings Inc. & Affiliates	No	1) The language in the Statement of Purpose needs to be reworded. The phrase "remove from service only those elements required to isolate faults" may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a

Organization	Yes or No	Question 1 Comment
		fault on the line, it would violate the requirement to “remove from service only those elements required to isolate faults”. The language used in the proposed definition of Protection System Study is slightly better, using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. 2) The problem here is who determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? 3) The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point.

Response: Thank you for your comment.

1. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”. The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.**
2. **Determining the “desired sequence” is the purpose of the Protection System Study agreed to by all parties involved.**
3. **The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: Protection Systems installed at Interconnected Stations for the primary function of detecting Faults on BES Elements. Additionally, the drafting team changed the term “Interconnected Facilities” to Interconnected Elements” defined as follows: “An Element that electrically joins separate Functional Entities, including**

Organization	Yes or No	Question 1 Comment
those Functional Entities that are a part of the same Registered Entity".		
Hydro One	No	1. The goal of this standard is to address co-ordination of protection systems between neighboring entities. To achieve this goal, the efforts should focus on the co-ordination of protections between entities as outlined and described in the NERC SPCS paper "Power Plant and Transmission System Protection Co-ordination - Technical Reference Document (TRD)," dated July 2010. This standard should include the review/study of all protections requiring coordination not the ones dealing with faults only as identified in the above TRD. There should be one comprehensive study/report not spread out into 7-8 standards. If so, there are still protection elements that require coordination that have not been addressed such as: open-phase, loss-of-field, over-excitation, out-of-step, and negative sequence normal unbalance, etc. We don't see how a standard for Protection system co-ordination can rely on other standards to achieve the goal of co-coordinating protections for both Faults and other conditions that challenge co-ordination. 2. The Purpose should be: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate from abnormal system conditions, while meeting the system performance specified within requirements established in NERC TPL Reliability Standards."If the above suggestions are not taken into consideration and the SDT decides to keep the requirements in the current form, the statement"...while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." should be changed to include exact reference to standards or at least group of standards the SDT is referring to.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. 1. **As noted in the Background information section, the drafting team believes that other aspects of coordination are or should be covered by other standards and it is appropriate for this standard to be limited to the stated Purpose.** 2. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Imperial Irrigation District (IID)	No	The SDT proposed Purpose is confusing. IID proposes the following Purpose language: "To coordinate Protection Systems for Interconnected Facilities, such that during faults, those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."
Response: Thank you for your comment. **The drafting team does not see the confusion in the present language and respectfully declines to make the suggested change. The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Bonneville Power Administration	No	The purpose of PRC-001-1 was "To ensure system protection is coordinated among operating entities." With the rewrite of PRC-001 to PRC-027, the standard drafting team has expanded the purpose to specify that only elements required to isolate faults are removed from service and that system performance established in other NERC standards is met. The two additions to the purpose of PRC-027 should be removed for the reasons described below. 1) The statement in the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", only serves to unnecessarily complicate the purpose statement. BPA recognizes that the NERC standard does not

Organization	Yes or No	Question 1 Comment
		void the requirements of other NERC standards; therefore, there is no need to state in the purpose that other NERC standards must be met. 2) The statement in the purpose, "such that those Protection Systems remove from service only those Elements required to isolate faults", drastically expands the scope of PRC-027 over PRC-001. With this new purpose, BPA believes this puts NERC in the position of micromanaging how protection systems are applied. Although most protection schemes are intended to remove only the faulted element, it is not necessarily a problem if additional elements are removed, and there might even be reasons to remove additional elements. In some cases it might be significantly less expensive to design a scheme that allows the removal of additional elements. Protection engineers need to have the flexibility to apply protection schemes that meet the requirements of the project at hand. Creating standards with absolute requirements on how protection schemes are applied and set will eliminate the flexibility necessary to implement effective and efficient protection schemes. The Standard Drafting Team (SDT) does not have the ability to foresee all possible protection scenarios, and to create a standard whose purpose is to remove from service only those elements required to isolate faults will create unnecessary expense and difficulty. BPA strongly recommends that the statement "such that those Protection Systems remove from service only those Elements required to isolate faults" be removed from the purpose and that the standard be modified to eliminate this requirement.

Response: Thank you for your comment.

1. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**
2. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such**

Organization	Yes or No	Question 1 Comment
that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.		
FirstEnergy	No	We do not believe the phrase "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is needed and may be confusing to the reader.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team removed the phrase: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."**		
Santee Cooper	No	It would probably be good to avoid using the term "coordination" as it can be considered as having two meanings, either the "coordinating" of the exchange of the data or the "coordinating" of the actual protective devices. Coordination should be taken out of the title and the purpose. "To Coordinate Protection Systems" could be changed to "To communicate and exchange Protective System data..." in the Purpose. The title could be changed to "Protection System Interconnected Facility Performance during faults"
Response: Thank you for your comment. **The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
Detroit Edison	No	It is suggested that ". . . the system performance specified within requirements established in other approved NERC Reliability Standards" be specified so that what needs to be met is clear.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.**		
PPL Corporation NERC Registered Affiliates	No	PRC-027 appears to have been written exclusively for vertically integrated power companies, and there is no justification for making the proposed standard applicable to independent GOs. The only role an independent GO fulfills in isolating faults is to trip the breaker if the generator or GSU has a problem; everything involving sequencing is in the Transmission Owner's (TOs) or Distribution Providers (DPs) system. Independent GOs are owned by separate legal entities than the applicable TO or Distribution Provider [DP] to which they are interconnected. Such GOs do not have the capability to perform the type of TO/DP system studies that appear to be contemplated by the SDT. The actions required of independent GOs should be to perform Protection System maintenance and supply data to other applicable entities, per existing standards PRC-005-1 and PRC-001-1.1, respectively.
Response: Thank you for your comment. **The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on**		

Organization	Yes or No	Question 1 Comment
the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.		
SERC Protection and Control Subcommittee	No	a) Recommend under Purpose, deleting: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003R1.3.7 already requires the entity to "demonstrate that system performance meets its Table 1 for Category C contingencies" (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. b) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to "Protection System Interconnected Facility Performance during Faults". Also recommended is to change the Purpose to read "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults." In PRC 027, using the term coordination should only be referenced when referring to the technical aspects of the relay coordination within a requirement when applicable. (In the current PRC 001 standard the meaning of the term "coordination" has, and still is, interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between

Organization	Yes or No	Question 1 Comment
		entities).
Response: Thank you for your comment. a. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".** b. **The drafting team agrees that the use of the term 'coordination' in PRC-001 did result in multiple meanings and potential confusion. The SDT believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
ISO RTO Council SRC	No	Is the intent of the coordination that is expected limited only to those protection systems related to intertie facilities between facilities owners? Or is the intent of the proposed standard to require coordination of protection systems to take into account outage and/or operating conditions between facilities owners beyond the immediate intertie facilities? In other words is this coordination requirement expected to be applied to relays that may not be directly involved in protection of intertie equipment?
Response: Thank you for your comment. **The intent of this standard is focused on those Protection Systems directly associated with the Facility Interconnections. However, as noted in R.3.1 it is recognized that there may be changes or additions either at an existing or new Facility associated with the Interconnected Element, or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).**		
Tennessee Valley Authority	No	a) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to: "Interconnected Facility Protection System Performance During Faults". Also recommend changing the Purpose to read: "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those elements required

Organization	Yes or No	Question 1 Comment
		to isolate faults." b) Recommend under Purpose, deleting: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The purpose without this clause is clear, concise, and consistent with the rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to “demonstrate that System performance meets its Table 1 for Category C contingencies” (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. c) In PRC 027, the term "coordination" should only be referenced when referring to the technical aspects of the relay coordination within a Requirement when applicable. (In the current PRC 001 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities).

Response: Thank you for your comment.

a. **The drafting team agrees that the use of the term ‘coordination’ in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**

b. **Based on all the comments received, the drafting team has removed the phrase “…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards”.**

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc., JRO00088	No	See comments posted by SERC PCS
Response: See response to SERC Protection and Control Subcommittee.		
ACES Power Marketing Standards Collaborators	No	Please strike "while meeting the system performance specified within requirements established in other approved NERC reliability standards." It provides no additional explanation for the purpose and these "other approved NERC reliability standards" apply regardless of this standard. In generally, it is not necessary to reference other NERC standards within a standard and, in fact, should be avoided as a standard should stand alone.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Kansas City Power & Light	No	1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The present purpose makes it appear that you are in violation of the standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used but the measures tend to measure agreement with the other entity. This is the reason that the present purpose needs to be

Organization	Yes or No	Question 1 Comment
		rewritten the auditors may interpret the purpose to indicate any misoperation due to setting issues is a violation.
Response: Thank you for your comment. 1. **The drafting team believes the standard does exactly what you stated. The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The Purpose states the reason for the standard and is the basis for everything else in the standard, but the Purpose is not a requirement and is not mandatory or enforceable. The individual requirements support the goal or Purpose of the standard.** 2. **The drafting team disagrees with the misoperation issue you describe. Misoperations can occur even when Protection Systems are fully coordinated and agreed upon.**		
Southern Company	No	1) Reference the 'required to isolate Faults '. In some cases the design of the protection system may take more Elements out than the faulted element, such as a transformer differential that trips a transmission bus and then opens a HS Bank disconnect. For this reason we would prefer the term 'as designed' be used. 2) We feel that it is important to identify the Protection Systems that are to be evaluated; perhaps a clear reference to the NERC Technical reference document?
Response: Thank you for your comment. 1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".** 2. **The Protection Systems that must be evaluated are those that are identified in the Applicability section of this standard.**		
Western Area Power Administration	No	Don't necessarily agree with the statement: "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote

Organization	Yes or No	Question 1 Comment
		Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated.
Response: Thank you for your comments. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults".**		
Independent Electricity System Operator	No	We agree with the first part of the purpose statement, but do not find it necessary to include the second part since "meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is universally true for all standards. No one single standard can assure reliability on its own; multiple standards must be complied with to meet one or more reliability objectives and performance targets. We suggest to remove the part "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
American Electric Power	No	AEP recommends the removal of the language, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards". AEP recommends as an alternative to the removal of the language, modification of the language to reference the TOP standards that should be adhered to in conjunction with PRC-027.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Texas Reliability Entity	No	We support this reliability objective, but feel that it may fall short of fulfilling all of the required Protection System coordination needs, resulting in a gap in the Standards. The major issue that we see in Protection System coordination is with coordination studies conducted WITHIN an individual entity, not between two or more entities. Using the Misoperation data as an indication, for CY2011, out of 202 total Misoperations in the ERCOT region, 46% were due to "Incorrect settings/logic design", however, less than 2% of the Misoperations occurred on Interconnected Facilities between different entities. This suggests the main problem with Protection System coordination is internal to an entity, not between two different entities. This Standard, as well as PRC-001, are somewhat silent as to what internal coordination should be considered "Good Utility Practice", even though there have been instances where internal coordination was not done.
Response: Thank you for your comment. **The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities' internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the scope of this standard. Additionally, PRC-004 requires that entities have corrective actions plans for identified Misoperations which would prevent similar Misoperations.**		
LCRA Transmission Services Corporation	No	Reword the Purpose to state as follows: "To allow for the coordination of Protection Systems at Interconnected Facilities to prevent equipment damage while maintaining proper selectivity during Faults." This phrasing is

Organization	Yes or No	Question 1 Comment
		more consistent with NERC Reliability Standard language where adherence with other reliability standards is not explicitly stated.
Response: Thank you for your comment. **The drafting team believes that restricting the purpose to "preventing equipment damage" does not meet the intended reliability objective.**		
Exelon	No	1. The current Purpose for PRC-027-1 should more clearly and concisely state the purpose of the standard by relating the purpose of the standard to the definition of Protection System Study (the key element of the proposed PRC-027). 2. The statement, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", is likely to be subject to interpretation by registered entities and auditors alike and cause confusion. The specific Standards should be referenced in a footnote, or the reference should be removed. [For the purposes of this comment and the suggested revision, Exelon removed the reference since we believe this is the best option].Exelon suggests the following revised Purpose "To ensure Protection Systems at Interconnected Facilities operate in the desired sequence to isolate a fault." In our experience, the term "coordinate" (or "coordination") caused confusion in PRC-001-1 and therefore Exelon proposes that the term be omitted. 3. In PRC-001-1, the term "coordination" was unofficially accepted as either the correspondence or communication between entities (i.e., via email, memo, fax, etc.), or as the time response relationship associated with backup protection elements. Thus, to avoid this confusion and to match to the proposed Protection System Study definition, Exelon removed it from our suggested Purpose statement above. If the SDT believes that the term "coordination" should

Organization	Yes or No	Question 1 Comment
		remain, it should be clearly defined. Given the Protection System Study definition, a suggested definition for coordination would be "operation of Protection Systems in the desired sequence to isolate a fault".
Response: Thank you for your comment. 1. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team believes that the Purpose does not need to address its relation to the Protection System Study in order to accurately reflect the goal of the standard.** 2. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".** 3. **The drafting team agrees that the use of the term "coordination" in PRC-001 did result in multiple meanings and potential confusion. The drafting team believes that the use of the term in this standard is clear and has not removed the term from the Title nor Purpose.**		
Ameren	No	We recommend that the SDT delete the last part of the purpose "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to "demonstrate that System performance meets its Table 1 for Category C contingencies" (TPL-001, -002 also have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Georgia Transmission Corporation	No	The title should state the same as the purpose. Example: "Protection System Coordination of Interconnected Facilities". The purpose is to make each entity communicate protection system and/or facility changes in order to make coordination changes as needed.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team believes the Title and Purpose, as separate components of the standard, are not obligated to be the same.**		
Dairyland Power Cooperative	No	The NERC Protection System definition includes more elements than would need to be coordinated at interconnecting facilities (e.g. batteries, chargers). Please consider revising to include only the protection elements that would need to be coordinated to remove Elements from service to isolate Faults.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults". The drafting team does not see that specific Protection System elements referenced (Batteries and chargers) would be considered in doing a Protection System Study; therefore, your suggested changes have not been made.**		
NPPD	No	Suggestion: Remove "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" since there are other standards that are or will be in place otherwise it sounds like the other standards must have evidence included

Organization	Yes or No	Question 1 Comment
		for this standard documentation as well. Perhaps this standard is not required if the other performance standards are adhered to or have portions of this draft standard included in them.
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Utility Services	No	The purpose should specifically state whether or not this standard applies to BES Elements or all Elements. In consideration of other PRC reliability standards, this standard uses language that implies applicability to all Elements. Under the NERC Standard Development Process, standards are only to be applied to BES equipment, unless the applicability language specifically states a broader application. This standard implies it but does not specifically state it. The standard should be modified to clear up any confusion.
Response: Thank you for your comment. **The definition of Interconnect Facilities has been modified as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". The Applicability section has been modified as follows: Facilities: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
Trans Bay Cable	No	The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.**		
Oncor Electric Delivery Company LLC	No	Oncor takes the position that the word "only" in the Purpose is too subjective and allows for multiple interpretations. Oncor believes that in order to provide clarity, Oncor suggest that the Purpose be modified as follows:"To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.
Response: Thank you for your comment. **The drafting team modified the Purpose, it now reads: “To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults”.**		
TransAlta Centralia Generation LLC	No	The Interconnected Facilities definition is not clear.
Response: Thank you for your comment. **The term “Interconnected Facilities” has been changed to “Interconnected Element” and reads as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”. More details related to why it is not clear are needed prior to addressing your comment.**		
ExxonMobil Research & Engineering	No	
MRO NSRF	Yes	The last part of the purpose, “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” is vague and open-ended. The NSRF recommends that the SDT refer to the TPL standards if the intent is to limit responsibility for correct

Organization	Yes or No	Question 1 Comment
		coordination to studied system contingencies
Response: Thank you for your comment. **Based on all the comments received, the drafting team has removed the phrase "…while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".**		
Colorado Springs Utilities	Yes	There are cases of weak system interconnected facilities where proper coordination may not be achievable economically, except by severing the interconnect. Allowances should be made for these cases to prevent the severing of weak systems to meet this standard.
Response: Thank you for your comment. **The drafting team does not understand the scenario that is described. If this occurs in circumstances not accounted for in normal Protection System Studies, such as n-2 and above situations, it is not an issue.**		
Sacramento Municipal Utility District	Yes	We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.
Response: Thank you for your comment. **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.**		
Public Utility District No. 1 of Snohomish County	Yes	1. We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very

Organization	Yes or No	Question 1 Comment
		narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We believes this is regulatory overkill and not indicative of a results based standard.
Response: Thank you for your comment. **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that PRC-027-1 should be tightly focused on Fault isolation only. There are other PRC standards which govern the coordination of UFLS, SPS, phase-distance, and other relay types.
Response: Thank you for your support.		
National Grid USA / Niagara Mohawk	Yes	
Luminant	Yes	
Northeast Power Coordinating Council	Yes	
GP Strategies	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Public Service Enterprise Group	Yes	
Liberty Electric Power LLC	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
Portland General Electric Company	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
mason	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Duke Energy	Yes	
Clark Public Utilities	Yes	
NextEra Energy Inc	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

2. The SDT assigned the Applicability of PRC-027-1 to Transmission Owners, Generator Owners and Distribution Providers that own the Protection Systems applied at the Interconnected Facilities that require coordination for isolating generation and Transmission Faults. Are you aware of other functional entities that should be included in the Applicability? If so, please provide specific suggestions in the comment area and the reason for including those functional entities.

Summary Consideration:

A large majority of the commenters did not identify any additional entities that should be added to the Applicability.

Various commenters felt that the Transmission Planner, Planning Authority, Transmission Operator and/or Generator Operator should be included. The basis for these requests was the fact that in some cases those entities were identified as providing the Protection System Studies and/or system modeling services for the Owners. An example response to these comments was as follows: The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others.

Several commenters disagreed with the Distribution Provider being included. The drafting team responses indicated that the inclusion of Distribution Providers was appropriate. The drafting team responded that they believe the Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A few commenters asked for clarification as to whether the standard applied to entities that had multiple registrations (i.e. as a TO and GO). An example response to these questions was as follows: If Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A- Generator Owner. The drafting team will review the language in order to ensure clarity related to this.

The Applicability was slightly modified as a result of these comments and others as follows: 4.2 Facilities: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.

Organization	Yes or No	Question 2 Comment
FirstEnergy	No	However, it should be clear the DP facilities in scope are only those associated with potentially impacting a BES facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.** **To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Additionally, the drafting team changed the term "Interconnected Facilities" to "Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Northeast Power Coordinating Council	No	From a reliability perspective, the Applicability Section of PRC-027-1 should not include the Distribution Provider because the TO is responsible of coordination of the protection with the DP.
Response: Thank you for your comment. **The drafting team believes that the owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Owner is providing such a service it would be by agreement, and does not change the fact the Distribution Provider has the responsibility.**		
MRO NSRF	No	The standard includes the definition of Interconnected Facilities as BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities. It is unclear how the requirements of the standard would apply if a registered entity would fulfill more than one functional entity role. For example if a registered entity was both a Generator Owner and Transmission Owner would the requirements of the standard apply to the interconnection of the generator and transmission facilities? It is recommended that the standard be modified to provide clarity for this situation.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Facilities between Entity A- Transmission Owner and Entity A- Generator Owner. **Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
PPL Corporation NERC Registered Affiliates	No	Applicability to GOs should be limited as stated above in question #1.
Response: Thank you for your comment. **As noted in the response to #1: The drafting team believes that the Owner of the Protection System is responsible for ensuring its Protection Systems are coordinated with others. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems owned by Generator Owners installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included.**		
Colorado Springs Utilities	No	The wording of the text suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are usually contained in different functional or corporate entities it suggests much more documentation, and needs clarified.
Response: Thank you for your comment. **The only Transmission to Distribution interfaces included in this standard are those where the Distribution Providers own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES. Consequently, these facilities are the only ones that would require documentation.**		
Tennessee Valley Authority	No	In some instances end-use customers, such as a large industrial load, take service delivery through an Interconnected Facility. It is not clear that the draft standard covers coordination between a TO and an end-use customer (not registered as a TO, GO or DP) who takes service via a BES Interconnected Facility.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team changed the term "Interconnected Facilities" to Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". The standard only applies to Interconnected Element(s) between registered Transmission Owners, Generator Owners, and Distribution Providers. . To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>1. The applicability should also include Transmission Operators and Generator Operators as it is possible for jointly held facilities to be owned by several parties and operated by another party and relay protection responsibilities could be with the Operator of the facility.

2. It should be clarified the proposed Standard is applicable to Distribution Providers that provide protection for BES Elements.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

1. The drafting team believes that the Owner of the facility is responsible for ensuring that its Protection Systems are coordinated with others. It is acknowledged that in some cases the scenario described may exist; however, if the TOP or GOP is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.

2. To add clarity to this issue, the drafting team revised Applicability Section 4.2 as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Additionally, the drafting team changed the term "Interconnected Facilities" to "Interconnected Element" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".</td></tr>
<tr><td>LCRA Transmission Services Corporation</td><td>No</td><td>We agree that applicability of the overall standard should be limited to the Transmission Owners, Generator Owners and Distribution Providers; however, requirements for conducting the Protection System Coordination Study should only</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		apply to the Transmission Owners, Generator Owners and Distribution Providers that have ownership of the protective relay portion of the Protection System. Requirement R1 should read as follows:"Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System that owns a Protection System shall:"
Response: Thank you for your comment. **The drafting team believes that the Applicability section addresses this. Typically the protective relay may be the only component of the Protection System that requires review; however, that is not always the case.**		
Tri-State G & T	No	We agree with this description and the entities, however the standard's applicability is not written as described in the question. We think that "that require coordination for isolating generation and Transmission Faults" should be added to Section 4.2, Facility Applicability.
Response: Thank you for your comment. **Based on yours and others comments, the drafting team modified the Applicability section 4.2 Facilities as follows: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements".**		
Wisconsin Electric Power Company	No	The previous version, we think correctly, did not include DP's in the applicability. Since the revised definition of the BES is currently awaiting FERC approval, the applicability of this standard to the Distribution Provider function is not appropriate. The relevant entities should be limited to TO and GO only.
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.**		

Organization	Yes or No	Question 2 Comment
Dairyland Power Cooperative	No	It is unclear how the requirements of this standard apply to entities that fulfill multiple functional roles. For example, an entity is registered as both a Generator Owner and Transmission Owner. In the case where a GO and TO are the same entity is it required to show the same type of coordination?
Response: Thank you for your comment. **Yes. The drafting team's intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.**		
American Transmission Company	No	ATC is not aware of additional functional entities that should be included.
Response: Thank you for your support.		
NPPD	No	1. This applicability needs clarification. How does this standard relate to the definition of BES? 2. Does including Distribution Providers mean an entity that does not own a transmission protection system is included under this standard? 3. There needs to be clear understanding that radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders are not included in this standard. 4. Perhaps NERC needs a program to evaluate/identify all functional entities and determine if they should be registered and thus applicable and not have utilities try to determine the status of other utilities or functional entities. 5. Clarify if the Transmission and Generator owner are the same utility how sharing of information is documented or confirm that this relationship means the documentation is not applicable in this standard.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team revised the Applicability of this Standard to provide more clarity, it now reads: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”
2. No. The drafting team believes Distribution Providers that do not own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES are not included in the Applicability of this standard.
3. As noted in the revised Applicability section, only Facilities that have “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements” are subject to the requirements of this Standard. In general, radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders do not have such Protection Systems applied. Please see Figure 4 in the Application Guidelines section of the draft standard PRC-027-1.
4. This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.
5. How to meet the documentation requirements would be up to the entity to determine. The drafting team’s intent is that if Entity A is registered as a Transmission Owner and a Generator Owner then all aspects of this standard would apply to the Interconnected Element(s) between Entity A- Transmission Owner and Entity A- Generator Owner.</td></tr>
<tr><td>Utility Services</td><td>No</td><td>However, using the broad term "Protection Systems", this SDT is broadening the scope of the standard beyond the BES. Due to the recent direction in Project 2007-17 for PRC-005-2, Protection Systems has been expanded to include systems beyond the definition of the BES. This project should limit the applicability for the DP to "transmission Protection Systems" as identified in PRC-004 and 005-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
The drafting team revised the Applicability of this Standard to address your and others’ comments, it now reads: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>The proposed term for Interconnected Facilities, shown on page 2 of 27 of PRC-027-1</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		Draft #1, is defined as "BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities." CenterPoint Energy believes Interconnected Facilities should be defined in reference to NERC registration and recommends changing the definition to "BES Facilities that are electrically joined by one or more Element(s) and are owned by different registered entities."
Response: Thank you for your comment. **The drafting team considered this option; however, the drafting team felt that 'registered entities' would potentially mislead some entities that have different functional registrations, to think that the Standard does not apply to them. The term Interconnected Facilities has been changed to Interconnected Element as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".**		
Dominion	No	
Southwest Power Pool NERC Reliability Standards Development Team	No	
National Grid USA / Niagara Mohawk	No	
Pepco Holdings Inc. & Affiliates	No	
Luminant	No	
Imperial Irrigation District (IID)	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 2 Comment
Santee Cooper	No	
Detroit Edison	No	
Western Small Entity Comment Group	No	
SERC Protection and Control Subcommittee	No	
Associated Electric Cooperative, Inc., JRO00088	No	
Southern Company	No	
Salt River Project	No	
Operational Compliance	No	
Pacific Gas and Electric Company	No	
Western Area Power Administration	No	
Independent Electricity System Operator	No	
American Electric Power	No	
Sacramento Municipal Utility	No	

Organization	Yes or No	Question 2 Comment
District		
Flathead Electric Cooperative, Inc.	No	
ExxonMobil Research & Engineering	No	
City of Austin dba Austin Energy	No	
Texas Reliability Entity	No	
Manitoba Hydro	No	
Xcel Energy	No	
Tacoma Power	No	
Ameren	No	
Public Utility District No. 1 of Snohomish County	No	
Georgia Transmission Corporation	No	
Platte River Power Authority	No	
MWDSC	No	

Organization	Yes or No	Question 2 Comment
Portland General Electric Company	No	
mason	No	
ATCO Electric	No	
Illinois Municipal Electric Agency	No	
El Paso Electric Company	No	
Trans Bay Cable	No	
Duke Energy	No	
Clark Public Utilities	No	
Oncor Electric Delivery Company LLC	No	
South Carolina Electric and Gas	No	
El Paso Electric	No	
Hydro One	Yes	1. This is related to our comments from Question 1. We believe that the Planning Coordinators (PC) shall be included. PCs are accountable to conduct studies to determine critical clearing times, stable and unstable power swings, etc., to determine coordination. Transmission and Generator Owners do not have access to such information or the

Organization	Yes or No	Question 2 Comment
		tools/experience to conduct such studies. In addition to this there is a possibility that the entity in charge of day-to-day operation of the Interconnection Facilities (likely registered as TOP only) doesn't own the facility and consequently is not registered as a TO. In this case, such facility or the facilities would be out of scope of this standard. We believe that the SDT should refine the Applicability section to encompass the above mentioned cases. 2. From a reliability point of view, we think that this standard should not be applicable to Distribution Providers because the TO is mostly responsible of coordination of the protection with the DP.
Response: Thank you for your comment. 1. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if PC is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.** 2. **The drafting team believes Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.**		
ISO RTO Council SRC	Yes	Depending on the intent of the requirements as questioned in the comment to question #1, it may be necessary to include planners to provide data for contingent and varying operating conditions to coordinate relays beyond those dedicated to intertie facilities.
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, the fact that the planners may be providing some data necessary to complete the evaluation it does not warrant including them in the Applicability.**		

Organization	Yes or No	Question 2 Comment
GP Strategies	Yes	1. We agree that there should be a process for ensuring that the industry continuously evaluates the system and ensures that the relay settings are coordinated and adjusted to meet the dynamically changing grid. However, we disagree that the studies should be conducted by the owners of the facilities. We feel these studied should be conducted by the Transmission Planner or Planning Authority and the cost of the studies should be allocated equally to all users of the grid. Currently, a study is performed when a new facility is added or an existing facility is modified. Typically, the study is conducted by the Transmission Planner as identified in FAC-002 and paid for by the facility that is being modified or is being added. It makes since that these facilities pay for the studies as they are the ones modifying the overall grid and benefit from the modification. In this case the cost should not be barred by an existing facility. 2. The drafting team states that an owner should perform a study when the fault current changes by 10% or greater at their Interconnected Facility. The team may not have taken into account the potential that these changes are not related to that particular facility but rather from a change in the overall dynamics of the grid. For example, an influx of renewable resources (both behind and in front of the meters), retirement of generation, changes to transmission, or changes in load pockets. In addition, it excludes any new facilities added since 2007 from sharing the cost of changes to the grid. The cost for studies conducted for changes to the existing grid should be allocated to all interconnected facilities and should be performed by the Transmission Planner. As defined in the Rules of Procedure, section 500, the Transmission Planner is "the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area." The Planning Authority is the entity that maintains the information required for the studies and is the entity that could perform the studies at the lowest cost. The cost for performing the studies should be allocated to all entitles doing business on the grid and the cost should be reviewed in a rate case and allocated appropriately.MOD-010 and MOD-012 already provides a requirement

Organization	Yes or No	Question 2 Comment
		to provide the characteristics for system studies to the RRO for updating the models that would be used to conduct the studies. 3. These Standards, however, have a gap in that they do not include Distribution Provider as indicated in the proposed PRC-027 Standard. We recommend the drafting team revise MOD-010 and MOD-012 to retrieve all necessary information to update the RRO model and that the Transmission Planner be tasked with performing the necessary studies.
Response: Thank you for your comment. 1. **The studies conducted by the Transmission Planner or Planning Authority related to FAC-002 are not necessarily directly related to the protection system study identified by this standard. The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the Transmission Planner or Planning Authority is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility. It is also noted that Protection System Studies are not generally conducted by the Transmission Planner or Planning Authority.** 2. **The observation that changes to the grid not directly associated with the Interconnected Element(s) is exactly the driver for the inclusion of a regular review of fault currents at the Interconnected Element(s). If such changes result in a 10% change in the conditions that were used in the last Protection System Study, the need for a new study must be evaluated; however, it does not require a study be done.** 3. **Modifications of the noted standards are outside the scope of this drafting team.**		
Idaho Power Company	Yes	Yes, Transmission Operators may own protection systems but not the interconnected element due to cost sharing agreements among Entities, for example. The applicability should be expanded to cover the Entity responsible for operation of the protection system element and interconnection.
Response: Thank you for your comment. **Based on the Functional Model, the drafting team does not see how the Transmission Operator would own Protection Systems without also being registered as a Transmission Owner. If such a scenario does exist, it is assumed that it would be by agreement**		

Organization	Yes or No	Question 2 Comment
with the Owner, and does not change the fact that the Owner has the responsibility.		
Exelon	Yes	Agree, all entities should be included if they are responsible for engineering of protection systems protecting BES elements at Interconnected Facilities.
Response: Thank you for your comment. **It is unclear to the drafting team which additional entities are being suggested for inclusion.**		
Public Service Enterprise Group	Yes	Within RTOs and ISOs, entities such as PJM and NYISO perform such evaluations as part of their transmission planning process. See PJM Manual 14-B, Appendix G, section G.7 which states: "PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment." Therefore, Transmission Planners should be considered as an applicable entity for R2 as discussed in #9 below
Response: Thank you for your comment. **The drafting team believes that the Owner of the facility is responsible for ensuring that their Protection Systems are coordinated with others. It is acknowledged that some cases the scenario described may exist; however, if the RTO or ISO is providing such a service it would be by agreement with the Owner, and does not change the fact the Owner has the responsibility.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	It would seem like Transmission Planners and Planning Coordinators would have a natural interest in modifications made to relay systems. Their simulations must show that BES performance under various contingencies meets certain criteria. Any information discovered in the course of the Protection System Studies would be of interest to them as well.
Response: Thank you for your comment. **The drafting team agrees; however, the Protection System data that may need to be provided by the owner to the Transmission Planners and Planning Coordinators is covered by other Standards.**		

Organization	Yes or No	Question 2 Comment
TransAlta Centralia Generation LLC	Yes	The applicability should include other functional entities which should provide power system study data.
Response: Thank you for your comment. **It is unclear to the drafting team which additional entities are being suggested for inclusion.**		
Liberty Electric Power LLC	Yes	
NV Energy	Yes	
ACES Power Marketing Standards Collaborators	Yes	

3. **In Requirement R1, the SDT allowed a responsible entity 36 months to have a documented Protection System Study completed for each Interconnected Facility if the responsible entity does not already have a Protection System Study for that Interconnected Facility performed on or subsequent to June 18, 2007 (the effective date of PRC-001-1). Do you agree with this time frame? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Many commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Elements enough time to complete the Protection System Studies, and that there is no evidence there is widespread miscoordination between Interconnected Stations; therefore, the drafting team changed the time frame to forty-eight months.

Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.

Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: “An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity”.

Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Affiliates	No	1. Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal “coordination study” in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected,

Organization	Yes or No	Question 3 Comment
		especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. 2. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. 3. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 36 month requirement.

Response: Thank you for your comment.

1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.**
2. **Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**

Organization	Yes or No	Question 3 Comment
3. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists.		
Hydro One	No	1. Hydro One would like to suggest that 60 months would be a more realistic span of time needed in order to formally complete a documented study, or derive a time frame based on the number of interconnections that an entity must conduct studies for. Whether the systems are co-ordinated or not, the work needs to be carried out and documented. In the case of Hydro One there are almost 300 individual generator connections that belong to other entities many of whom do not have onsite protection experts. Most of these connections do not have a formal documented protection co-ordination study. 2. Statements in R1.1.2 and 1.1.3: "unless the entity can demonstrate such a study is not required." and its corresponding measure: " or documentation demonstrating why a study is not required for changes described in Parts 1.1.2 and 1.1.3" are vague and don't give much guidance on what would be the appropriate evidence in this case. 3. Suggest adding examples of documents that can be used to demonstrate compliance.
Response: Thank you for your comment. **1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element**		

Organization	Yes or No	Question 3 Comment
exists" 2. Based on your comment, the drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". 3. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."		
Bonneville Power Administration	No	1. This question assumes that the requirement to perform a protection system study is acceptable, and the question focuses only on the timeframe allowed. In BPA's opinion, the requirement to have a protection system study is objectionable and cause for disapproval of the standard. Therefore, the timeframe is irrelevant. 2. In addition, the standard fails to make clear just what a protection system study is, either in the definition, the requirements, or the guidelines that follow. BPA believes that R1 is ambiguous and unacceptable.
Response: Thank you for your comment. 1. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. 2. The drafting team made various changes including those to the definition, requirements, and guidelines to clarify what a Protection System Study is. Other commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system		

Organization	Yes or No	Question 3 Comment
Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”		
FirstEnergy	No	Requirement 1, Part 1.1.1 - Although we agree with the timeframe, the phrase “within 36 calendar months after the effective date . . . . subsequent to June 18, 2007” should not be listed as a requirement but rather as part of the Implementation Plan.
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”**		
Detroit Edison	No	Why aren’t studies performed prior to June 18, 2007 considered acceptable if they’re still valid as long as no significant fault current or system changes have occurred?
Response: Thank you for your comment. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).”**		
MRO NSRF	No	1. If an entity has a Protection System Study performed prior to June 18, 2007 that

Organization	Yes or No	Question 3 Comment
		meets the requirements for the study specified in PRC-027-1 and there have been no changes to trigger a new study as specified in PRC-027-1 (that have occurred) the study should be acceptable for compliance with the standard. It is suggested that the requirement R1, sub-requirement R1.1 be revised by removing the phrase "that was performed on or subsequent to June 18, 2007." 2. The NSRF questions if 36 months is ample enough time for large company to get all studies done within 36 months. Unless R1.1 is revised to mean all studies regardless to when it was performed.
Response: Thank you for your comment. 1. **Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."** 2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Elements. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
PPL Corporation NERC Registered Affiliates	No	As noted in the response to question #1, TOs and DPs have the data and the capability needed to perform the studies that appear to be contemplated by the SDT.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team agrees.		
Tennessee Valley Authority	No	1. "Protection System Study" is a new term being introduced with this standard. Since industry documentation of protection system coordination reviews are conceivably available from both before and after June 18, 2007, precluding coordination reviews performed prior to June 18, 2007 from acceptable compliance evidence could greatly increase the workload of protection system engineers during the proposed 36 month time period. Note that there is a possibility of overlap with the "Order 754 request for data" response period. The rationale statement for R1, Part 1.1.1, indicates that the effective date of PRC-001-1 was the basis for selecting June 18, 2007. PRC-001-1 primarily addresses new protective systems and changes (R3 & R5) and coordination with neighboring GOP, TOP and BA entities (R4). We suggest changing the wording of Part 1.1.1 to the following: "Within 36 calendar months after the effective date of this standard, if no valid Protection System Study for that Interconnected Facility exists."
Response: Thank you for your comment. **1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).**		
ACES Power Marketing Standards Collaborators	No	(1) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement implement what is explained in the application guidelines. For instance, nowhere in Requirement R1 is it stated clearly that the responsible

Organization	Yes or No	Question 3 Comment
		entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Facility. This is pretty clear in the application guidelines. (2) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (3) We disagree with limiting PSS that can meet this requirement to only those that occurred after June 18, 2007 as defined in Part 1.1.1. While NERC cannot compel evidence from a date before the standards became enforceable, there is no reason that a TO, GO, or DP could not choose to utilize a PSS from before this date as evidence. (4) We think the use of PSS in Part. 1.1 is partly redundant to the definition. The definition indicates PSS is a study that demonstrates Protection Systems operate in desired sequence for clearing Faults. Part 1.1 states that the TO, GO, and DP shall perform the PSS "to verify Protection Systems remove from service only those Elements required to isolate Faults" are removed from service. Isn't the statement in Part 1.1 "to verify Protection Systems remove from service only those Elements required to isolate Faults" equivalent to the demonstrating that Protection Systems operate in the desired sequence for clearing faults as defined in the PSS? (5) We disagree with including the Distribution Provider in this requirement. The primary reason that a Distribution Provider owns Protection Systems that protect Interconnected Facilities is that it is often cheaper to install a fault interrupting device and its associated Protection Systems on the distribution side. These Protection Systems are typically installed per the Transmission Owner facility connection

Organization	Yes or No	Question 3 Comment
		requirements which are established per FAC-001. The Transmission Owner usually still performs the PSS and short circuit study and the Distribution Provider uses settings specified by the Transmission Owner. The fact that FAC-001 applies only to the TO and allows the TO establish such facility connection requirements that applies to the DP further supports this claim. (6) The definition of Interconnection Facility is confusing and needs further refinement. First, we are not sure what the purpose of including "that are electrically joined by one or more Element(s)" is. If it is not electrically joined, it cannot be a Facility. It would not be part of the BES which is a basic requirement of the Facility definition. Second, it is not clear if this is intended to cover only jointly owned Facilities or not. We do not think that is the intention but the clause "are owned by different functional, operating or corporate entities" cause this confuses. Third, ownership cannot be defined by functional or operating entities. A corporate entity may be registered as a TO and GO. Which part of the definition applies for the interconnection between the transmission system and generator: Functional Entities or Corporate Entities? Furthermore, a functional entity or operating entity does not really describe a legal entity capable of ownership. The definition of Interconnected Facility should be a Facility that ties together two different sets of Facilities together where the Protection System coordination would be performed by different companies. This would appear to be consistent with the explanation of the standards in the application guidelines. For example, a Facility connecting two different TO transmission systems together where the TOs are owned by separate corporate entities would be an Interconnected Facility. A generation interconnection Facility would only be considered an Interconnection Facility if the GO and TO were separate corporate entities. If they were the same corporate entity, coordination would already occur and the generation interconnection Facility should not be considered an Interconnected Facility.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. The drafting team believes that the Entity is responsible for conducting the PSS as described in the application guidelines. 2. Making the time frame part of the Requirements was the choice of the drafting team. 3. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. 4. Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Element defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity". 5. The Applicability of this standard includes Protection Systems installed for the primary function of detecting Faults on BES Elements irrespective of what functional entity owns them. Protection Systems not installed for the primary function of detecting Faults on BES Elements are not included in the Applicability. 6. Several commenters stated that the definition of Interconnected Facility is confusing. The drafting team changed the term to Interconnected Elements defined as follows: Interconnected Elements: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity".		
Kansas City Power & Light	No	The protective systems were coordinated when installed. If the power system has not undergone any significant change, then line impedances and fault current levels are the same and the original settings are still valid. So, no new study is required based on the passage of time. A new study is needed only if there have been significant system changes as outlined under question 5 and requirement R3.Requirement 1.1 states each entity must perform a system protection coordination study, however, the coordination efforts will be joint efforts between the entities and sharing of pertinent information such that an effective study can be performed. The proposed Standard should make it clear the study effort can be a joint study between the entities involved and that independent studies are not necessarily intended by each entity.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team acknowledges that the identified Protection System Studies can be a joint effort but believes they do not have to be. The drafting team agrees with the concept of joint studies as long as all involved entities have the required documentation.		
Southern Company	No	60 months would be more reasonable for those that have a large number of generators and/or interconnections. Perhaps a tiered approach: 36 months for those with less than 50, 60 months for those with more than 50 but must have 50% done within 36 months?
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
Salt River Project	No	The requirement to provide a copy of each Protection System Study is an administrative burden that does not reflect the intent of Results Based Standards. Changing the requirement to maintain evidence that Protection System Studies are coordinated and affected entities have agreed to the results of the Studies is adequate.
Response: Thank you for your comment. **The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities.**		
Pacific Gas and Electric Company	No	PG&E we believes that the 6 calendar month time frame in requirement R1.1.2 is too short and should be extended to 12 calendar months
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team believes because fault current reviews are conducted every 2 years, the expectation is that the number of instances where the fault current changes by 10 % will be limited. We therefore believe that the 6 month time frame is appropriate and decline to make the suggested change.		
American Electric Power	No	1. 36 months is not adequate for unique Protection System Studies to be conducted for the TO, GO, and DP. The interface and coordination requirements as written will require close communication with a vast number of interconnected facilities. In addition the generation landscape changes over the next few years with the large number of generation retirements and additions will continually change the short circuit model. AEP believes that these contributing factors will lead to time requirements above the proposed 36 months currently in the standard. AEP would require a minimum of 60 months to complete this work as the AEP system exists today. An added complication that will impact this time requirement is the approval of FERC Order 1000, which could result in additional interfacing TO's inside AEP's footprint. In addition, NERC's rationale for R1 states that "the SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. 2. Using the word "demonstrates" within the definition for Protection System Study could be interpreted as requiring an actual, operational test rather than a simulation study. We recommend changing the definition to "a study that demonstrates that the existing or proposed Protection System design will enables the Protection System to operate in the desired sequence for clearing Faults." 3. Is using the defined term "Protection System" appropriate? Does it possible bring things into scope (CTs, PTs, Station batteries) which should not?
Response: Thank you for your comment. **1. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations**		

Organization	Yes or No	Question 3 Comment
enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists". 2. The definition of Protection System Study refers to "a study that demonstrates"; consequently, the drafting team believes the word "demonstrates" is appropriate in the context it is used. 3. As stated, the Protection System does include CTs and VTs which are part of the considerations used when determining the settings of a protective relay. The information needed to be transmitted to another Entity would include this equipment.		
Sacramento Municipal Utility District	No	There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
Response: Thank you for your comment. The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.		
Idaho Power Company	No	1. No, Should a Protection System Study under R1 result in triggering of the other Requirements in the Standard, more time may be needed. 2. An Entity could easily find themselves responding to multiple inquiries from Interconnectors while performing their own Studies. Additional time should be allowed to address the results of the Protection System Studies triggered during this implementation timeframe.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **1. The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other changes that may result from the Protection System Study and are covered by Requirements R3 and R4.** **2. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies.**		
Exelon	No	Exelon cannot agree to the time frame proposed without understanding the scope of work involved in the required protection system study. 1. The current definition of Protection System Study (PSS) is not clear enough to avoid confusion. To better define the "study" as referenced in PRC-027-1 and to ensure that applicable entities know what they're required to do, the definition of PSS needs to clarify the elements of the protection system and power system conditions the study is run similar to how required Transmission Planning studies are defined. With this in mind, Exelon suggests the following definition for "Protection System Study": A study that demonstrates that existing or proposed Protection Systems operate in the desired sequence for clearing a fault. The study is conducted with a single power system element out of service and all Protection System elements in service, and with all power system elements in service and a failure of a single protective relay, communication system, ac current input, ac voltage input, or DC control circuit (these can be further defined using the information and Table from Order 754). 2. Exelon suggests that "summary results of a protection system study" should also be defined with clear parameters established. Unless the specific particulars are established, Exelon predicts that there will be confusion as auditors attempt to decide whether or not a piece of evidence will qualify as a "summary" of a Protection System Study. This is similar to the ambiguity in the existing revision of PRC-005-1 R1.2 which requires a "summary" of maintenance and testing procedures, yet does not describe specifically what is required. It is our experience that registered entities and auditors historically have had differences

Organization	Yes or No	Question 3 Comment
		of opinion about what constitutes a "summary".
Response: Thank you for your comments. 1. **Based on your comments and others, the drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)." Additionally, language has been included in the Guidelines and technical Basis section of the standard to indicate "System conditions used in Protection System Studies include maximum generation and transmission system at normal operating conditions and under single contingency conditions."** 2. **Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**		
Liberty Electric Power LLC	No	I disagree with the requirement for a protection system study. From the draft standard: "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities". There are approximately 18,000 generators in the US. Requiring each to perform a system study would result in costs running into the hundreds of millions of dollars. This will result in lower BES reliability as entities transfer funds from other reliability efforts to comply with this standard.
Response: Thank you for your comment. **The drafting team believes the requirements of this standard will enhance the reliability of the BES.**		
Public Utility District No. 1 of	No	Comments: There is no need to have a Protection System Study available for review

Organization	Yes or No	Question 3 Comment
Snohomish County		for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	1. This requirement assumes that a material percentage of the many thousands of interconnecting relay systems have a problem. There is no evidence of this; and in fact, the Rationale text box for R1 states that the converse is true. This makes sense, as the inter-operation of Fault isolation Protection Systems is a fundamental and well-understood concept - which may not be the case with the more complex relay types. In our opinion, the two-year TO assessment will be sufficient to catch an issue and drive improvements afterwards. Therefore requirement R1.1.1 should be deleted. 2. In addition, we do not agree with the "on or subsequent to June 18, 2007" time frame, since these studies are completed when a facility is built, and/or when a facility is significantly changed, which could quite possibly be prior to 2007. If studies were completed before June 18, 2007, and nothing significant has changed, the study meets the PRC-027 requirement, and/or the TO assessment does not indicate a need, there is no purpose served by repeating the study.
Response: Thank you for your comment. **1. For entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to create a baseline for use in the two year TO assessment as outlined in Requirement R2.**		

Organization	Yes or No	Question 3 Comment
2. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2.		
Wisconsin Electric Power Company	No	1. In some cases there may be many Interconnected Facilities between two or more owners. It cannot be expected that owners will be able to support performing multiple studies in parallel, at the same time. It would be best to eliminate the specified timeframe, and allow the owners the latitude to determine the timeframe based on priorities decided by them. 2. Also, replace the phrases in R1.1.2 and in R1.1.3, "... unless the entity can demonstrate such a study is not required", with "unless the entities involved agree that a study is not required". If the interconnected entities agree that a study is not required, there should be no requirement to document the reasons why a study is not required. Likewise, revise M1 to include as acceptable evidence "documentation that the relevant entities have agreed that a study is not required."
Response: Thank you for your comment. 1. The time frame for Requirement R1 has been increased to forty-eight months and the drafting team believes this time is sufficient to perform all required studies. 2. The drafting team revised Requirement 1, Parts 1.1.2 and 1.1.3 to include the phrase: "or technically justify why such a study is not required". As stated in the Rationale box for Part 1.1.2, one example of a technical justification would be: "when a line is protected by dual current differential systems with no backup elements set that are dependent upon Fault current". Documentation is needed to verify that an agreement was reached.		
NV Energy	No	With such a long time frame for conducting this subject study, one cannot assure that the protection systems are coordinated, and there could be an impending mis-coordination that goes uncorrected. Suggest 12 or 24 months.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".		
Dairyland Power Cooperative	No	It is agreed that the there needs to be a time period for Protection System Studies to be performed after the standard takes affect. However, the length of time is a concern due to the industries existing resources. It would be preferred that the time period be lengthened to 60 months.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time – suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
Platte River Power Authority	No	There is no need to have a Protection System Study available for review of every Interconnected Facility. The results based objective is that the registered entities communicate and coordinate. a simple statement by both entities that they have communicated and coordinated is sufficient.
Response: Thank you for your comment. **The standard requires a Protection System Study be performed but only requires a summary be provided to the other entity. The standard provides for documentation of the agreement which may be a simple statement as you indicate.**		
MWDSC	No	1. Protection Systems installed prior to June 18, 2007 should not be required to redo

Organization	Yes or No	Question 3 Comment
		a study because a system study should have been performed prior to installation based on the interconnected configuration at that time. The interconnected systems will change over time and redoing studies will raise more questions on assigning responsibility for changes beyond the control of the protection system owner. 2. For protection systems installed prior to June 2007, TOs should only be required to show a study was performed and coordinated with appropriate interconnected entities.
Response: Thank you for your comment. **1. Several commenters questioned why Protection System Studies performed prior to 6/18/07 would not be acceptable. The drafting team modified Requirement R1, Part 1.1.1 to make these studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."** **2. A valid Protection System Study will require the same documentation, regardless of the date of completion.**		
American Transmission Company	No	1. ATC does not agree with the time frame proposed. 2. The existing requirements in PRC-001 do not require protection system studies with Distribution Providers. As such, even though studies have been completed there may be no package (documentation) to support an audit. This requirement assumes that, if there is no existing fault study, one needs to be completed. If there have been no changes in short circuit or protective schemes, allow for completion of the studies based upon prioritization using voltage class and loading level.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists"** 2. **The drafting team modified Requirement R1, Part 1.1.1 to make studies acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2 which now reads: "Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed)."**		
NPPD	No	To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6-10 years (time depends on the number of applicable system ties as well)
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
CenterPoint Energy	No	(a) The proposed term for Protection System Study, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults." CenterPoint

Organization	Yes or No	Question 3 Comment
		Energy recommends Protection System Study instead be defined as "A study that demonstrates Protection Systems operate as desired for clearing postulated short circuit Fault events." (b) CenterPoint Energy believes a 36 month implementation to have a documented Protection System Study completed for each Interconnected Facility is overly burdensome, unless certain Interconnected Facilities are exempted. CenterPoint Energy recommends exempting Interconnected Facilities that are serving only load and that are connected by no more than two transmission line Elements that are operating between 100 kV to 200 kV. Many of these Interconnected Facilities have fault-proven, time-proven protection system set points. Additionally, Draft #1, on page 5 of 27, notes that protection system misoperations related to coordination issues are addressed by PRC-004.
Response: Thank you for your comment. **a. The definition of Protection System Study refers to "a study that demonstrates"; consequently, the drafting team believes the word 'demonstrates' is appropriate in the context it is used.** **b. Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**		
NextEra Energy Inc	No	While 36 months is allowed for studying all interconnections, what time is allowed for mitigation of identified setting or hardware change? If an issue is discovered, then an additional 12-24 months mitigation time should be allowed.
Response: Thank you for your comment. **The Requirement R1 time frame only addresses performing a Protection System Study; this time frame is not inclusive of other**		

Organization	Yes or No	Question 3 Comment
changes that may result from the Protection System Study and are covered by Requirements R3 and R4.		
Oncor Electric Delivery Company LLC	No	Given the “agreement” requirements defined in Requirement R4 and the uncertainty of its interpretation, many of the recent protection system studies may have to be performed again. Therefore, a more appropriate timeframe would be 5 years to have all applicable Protection System Studies completed.
Response: Thank you for your comment. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: “Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists”.**		
Western Area Power Administration	No	
ExxonMobil Research & Engineering	No	
National Grid USA / Niagara Mohawk	Yes	As a TO our experience has been that many GOs do not reply to requests for information. If the 36 month window cannot be met by a TO because information requests are ignored what recourse does the TO have to avoid a penalty for non-compliance?
Response: Thank you for your comment. **Requirement R3, Part 3.2 specifies that the “Requested information related to the coordination of Protection Systems associated with an Interconnected Element within 30 calendar days of receiving a request or according to an agreed-upon schedule.” In your example, the GO would be in violation of this standard.**		

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative, Inc., JRO00088	Yes	AECI objects with the line of questioning here, because it does not fully address all aspects of Requirement R1. While AECI appreciates the 36 month time-frame, we did receive internal comment back from our planning engineers Relay Operations Sub-Committee: 1) Concerning our Regional Entity's Short Circuit Data Working Group, the current status is such that a unilateral AECI SC study would be technically difficult. 2) Further, significant modeling development will be necessary in order for entities to comply with this requirement through a regional study formation, i.e. 3 yrs is a definite push on the timeline on the Initial pass. 3) Finally, the information to be reported from a Protection System Study R1.1, and particularly the information to be communicated to other entities R1.2, may be too vague. This primary concern is for personnel being inundated by the sheer volume of data that can now be performed in relation to such studies. AECI would appreciate the SDT providing further Industry Guidance as to what would constitute a clear and concise set of information, to be transmitted or received from corresponding parties.

Response: Thank you for your comment.

1. **The drafting team believes that a short-circuit study is required to meet the requirements of this standard and acknowledges that this is a collaborative effort.**
2. **Many of the commenters suggested that 36 months was not enough time - suggested time frames varied widely up to 10 years. The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists".**
3. **Requirement R1.2 has been modified to include additional details for the summary of results as follows: "or technically justify why such a study is not required".**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Flathead Electric Cooperative, Inc.</td><td>Yes</td><td>This seems like an adequate time, but it is unclear that smaller transmission dependent utilities really need to do this to maintain reliability and if their ratepayers would see any reliability benefit.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

This standard is applicable to Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.</td></tr>
<tr><td>LCRA Transmission Services Corporation</td><td>Yes</td><td>Requirement R1 should read as follows:”Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall:

”Requirement R1.1.2 should read as follows: Within 6 calendar months after determining or being notified of a change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. In the case where different portions of the Protection System are owned by different entities, then the Protection System Study must be a collaborative effort.
2. The drafting team revised Requirement 1, Part 1.1.2 to include the phrase: “or technically justify why such a study is not required”.</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td>The standard does not specify M2 violation reporting responsibility or assignment of violation due to non-responsiveness of the interconnected entity. Clarification needs to be made as to what is considered acceptable evidence that the affected entity received the study results under measure M2. Would a registered mail confirming receipt at an address be considered acceptable evidence; if not what type of document service would be considered acceptable?</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **Registered mail confirming receipt at an address would be considered acceptable evidence. Additional acceptable evidence would be letters, or emails acknowledging receipt.**		
Public Service Enterprise Group	Yes	We do not believe this requirement has been justified for the several reasons listed below. In addition, the “Protection System Study” definition is too vague as to what it should include. We suggest a separate appendix that lists the items that this study should address. We also suggest that the SDT develop several baseline and change case Protection System Study examples, using a common format. These should be incorporated into an appendix within the standard. a. The format and overall purpose of the baseline study has not been provided. It is highly unlikely that a sufficient Protection System Study has been completed or is available for a majority of the Interconnected Facilities since 6/18/2007 within North America. This is due in part to either no modifications being performed at these facilities or lack of data retention (a study was performed but since it was not a requirement, documentation is not available). To require entities to now perform such studies would be a sizeable undertaking and create a tremendous burden to all entities with little benefit to the entities and the reliability of the BES. For older Interconnected Facilities where no changes have been made in several decades, no benefit to the facility or the BES would come from perform such a study. b. The only time a Protection System Study should be performed is when a driver is in place that will require a possible relay setting changes. These drivers should be spelled out specifically. For example, if there is substation project work that requires relay setting changes, if the relays are being replaced, if a “tie line” is being re-conductored, etc. The requirement to perform a study should also apply to those “interface” relaying schemes that would normally require periodic review. The requirement for a periodic review will be driven by something other than a system configuration change. This may include schemes that have current operated relaying

Organization	Yes or No	Question 3 Comment
		where the setting of the relay is dependent of fault current level. c. The complexity of such a study is uncertain. In most cases, the “interface” relaying between two TO’s or a TO and a GO is very straightforward. In the case of the “interface” between a TO and a GO, the relaying may simply be a transformer differential scheme. In the case of a tie line between two TOs, if the relaying is strictly impedance based, then there is no need to perform a baseline study. In other cases, the study may be more complex. The study may also have to incorporate Protection System devices beyond the Interconnected Facility (e.g. BOP protection for generators, adjacent line or bus protection for transmission facilities). This would increase the amount of time and complexity required to perform the study. How would the SDT define the appropriate protection coordination boundaries for an Interconnected Facility?
Response: Thank you for your comment. **a. Several commenters asked what documentation was required for a Protection System Study. The drafting team modified the minimum attributes of a Protection System Study summary identified in Requirement R1, Part 1.2 which now reads: “Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed).” Entities that do not have a Protection System Study as specified in Requirement R1 will need to conduct a study to verify Protection System coordination and to create a baseline for use in the two year TO assessment as outlined in Requirement R2.** **b. Requirements R2 and R3 provide the triggering points that indicate when a new study is necessary.** **c. The drafting team acknowledges that the complexity of the Protection Systems applied will determine the scope of a Protection System Study and in some cases may not be required; however, this does not preclude the need for a baseline study. Application Guidelines provide examples of the protection boundaries.**		
mason	Yes	Although the timeframe appears reasonable, the more basic question about the necessity of the documentation requirements needs to be reconsidered.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.		
Duke Energy	Yes	However R1 is confusing by having two sub-requirements R1.1 and R1.2, two measures M1 and M2, and VSLs consisting of various combinations of non-compliance with sub-requirements. We think it could be made clearer by separating R1.2 out as a separate requirement with its own measure and VSLs. We have made a similar comment on Question 8 that other requirements, measures and VSLs in this standard could be made clearer by breaking them apart. Also, Requirement R1.2 states "each affected Interconnected Facility owner" without describing how the owner may be affected.
Response: Thank you for your comment. **The drafting team used the format recommended by NERC staff.**		
Dominion	Yes	
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Luminant	Yes	
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	

Organization	Yes or No	Question 3 Comment
SERC Protection and Control Subcommittee	Yes	
Colorado Springs Utilities	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 3 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
Trans Bay Cable	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	

4. In Requirement R2, the SDT established a +/- 10 % change in an Interconnected Facility's Fault current value as a criterion for notifying interconnected entities to give the interconnected entity a "heads up" that a review of the existing documented Protection System Study may be warranted. Do you agree with the +/- 10 % Fault current threshold for initiating this review? If not, please provide an alternative means along with a technical justification for determining a threshold.

Summary Consideration:

A majority of the commenters agreed with the 10% deviation trigger. Of those that disagreed and provided an option, they suggested a range of 15-20%. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows timely notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.

Multiple commenters expressed confusion as to where the fault needed to be applied, what branch(s) needed to be monitored, and what system conditions needed to be considered. Some expressed that the fault should be applied at the bus so that batch studies could be run to automate the short circuit study. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

Based on comments, the drafting team reworded Requirement R2 to provide clarity. The requirement now reads: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall:"

Several commenters suggested modifying the equation to replace "V" with "I". The drafting team made the change.

Organization	Yes or No	Question 4 Comment
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation

Organization	Yes or No	Question 4 Comment
		between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation...” The existing wording requires one to “calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration”. 3. Including the phrase “or Element(s) under consideration” increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each “element under consideration” used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a “batch” screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 “Additions, removals, or replacements of transmission Elements”.

Response: Thank you for your comments.

1. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read “Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus,**

Organization	Yes or No	Question 4 Comment
not less than once every 24 months." 2. The drafting team believes the existing wording was sufficient and did not make your suggested change. 3. The drafting team did remove the word "or Element(s)" as you suggested.		
Hydro One	No	Hydro One agrees with the need of a defined fault current threshold. However, we'd like to suggest a 20% threshold instead as most protection settings, if coordinated properly, must coordinate with system normal and under credible minimum system conditions, therefore, it is our opinion that a 10 % change should generally not affect coordination.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Bonneville Power Administration	No	This question assumes that the requirement to perform a mandatory short-circuit study every 24 months is acceptable, and the question focuses only on the percent change of the study results that will require notification. BPA believes that a short-circuit study should not be required and the percent change that triggers notification is irrelevant.
Response: Thank you for your comment. **The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Detroit Edison	No	Recommend that the "trigger" be a system change (line, transformer, generator) that

Organization	Yes or No	Question 4 Comment
		results in an impedance change.
Response: Thank you for your comment. **Requirement R3 of this standard allows for system changes to trigger a study as you suggest. However, the drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.**		
Northeast Power Coordinating Council	No	1. Agreed that a change in fault current is a method to trigger a coordination study, but a 15% threshold would be more efficient (+/- 15 %). 2. Clarify where the fault is to be applied and where the deviation is to be observed. One possibility is to apply the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to that bus.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** 2. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Response: Thank you for your comment. **Please see the SDT's response to your comments in question #1.**		
Colorado Springs Utilities	No	In order to avoid burdensome paperwork of traditional fault study values and existing

Organization	Yes or No	Question 4 Comment
		fault study values, common thresholds should be determined for initiating a review. Common thresholds can be common device ratings, or agreed upon levels at interconnects. As in Facility ratings, each owner should have device ratings for device capacities and can include short circuit ratings, which if exceeded can initiate a review.
Response: Thank you for your comment. **The drafting team agrees with your comment about establishing a common threshold but it is related to Protection System coordination rather than device ratings. The threshold we arrived at is a 10 % deviation of the Fault current values used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1.**		
Tennessee Valley Authority	No	1. The 10% change is too narrow for protection system studies. Accuracies of PT, CT, wiring, and modeling all add together and therefore the threshold for a new protection system study should be 15%.a) 2. In R2, Part 2.2, replace the term “deviation” with “change.” (Note: For this calculation all that’s required is to calculate percent change. i.e. Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; "the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function.) 3. In R2, Part 2.2, replace the term “present” with “new” and the term “most recent” with “previous”. Also reflect this terminology change in the % Change equation.(the use of the terms “present” and “most recent” can be perceived to be the same.) 4. It is also recommended that “V” for value be replaced by “I” for current. d) In R2, Part 2.1, please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the fault current values under normal conditions, not less than once every 24 months."

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.** 2. **The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change".** 3. **The drafting team believes that the terms "present" and "new" are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** 4. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I". The drafting team modified Requirement 2.1 to read "Perform a short-circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus, not less than once every 24 months."**		
ACES Power Marketing Standards Collaborators	No	(1) While we do not have an issue with the +/- 10% Fault current threshold, we question if the TO should be responsible for calculating the percent deviation for all Protection Systems for all Interconnected Facilities. Rather the TO should be responsible for calculating Fault currents on its transmission system and should be required to calculate the percent deviation for only those breakers and associated Protection Systems it owns and are protecting an Interconnected Facility and that it has performed the Protection System Study (PSS). The TO should communicate the Fault current to the owners of other Protection Systems protecting the Interconnected Facilities for them to calculate the percent deviation. (2) The main part of the requirement needs to be modified to further clarify for which Interconnected Facilities the TO is conducting short studies. As it is written now, each TO has to perform these short circuit studies for each Interconnected Facility. This literally means a TO has to perform short circuit studies for Interconnected Facilities for which it has no information or is even remotely responsible. For example, a literal reading would mean a TO in the Eastern Interconnection would have to perform a short circuit study for an Interconnected

Organization	Yes or No	Question 4 Comment
		Facility in the Western Interconnection. Obviously, this is not the drafting team's intention but the language does need refinement.

Response: Thank you for your comments.

1. **The drafting team changed the text in Requirement R2 to read: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall".**
2. **The drafting team changed the text in Requirement R2 to read: "For each Facility associated with an Interconnected Element on its System, the Transmission Owner shall".**

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	No	a. Primary protection of most transmission lines is impedance based. Sensitive ground over current systems are used for communications assisted tripping and time ground over current systems are typically used as backup protection. Some line protection is differential based. Some entities also apply instantaneous ground over current relaying for faults at some fraction of the protected line. Increases in fault current do not affect impedance based relaying. Communications assisted sensitive ground elements are set well below available fault current levels and increases in fault current levels will not hinder proper operation. Differential based systems would also not be harmed by fault current increases unless fault currents increase enough to result in ct saturation. Since time ground over current relays are usually used as backup protection they are typically set only to operate if the primary relaying protection has failed. These relays are typically set to coordinate based on time delays for ground faults on the protected line. Because the overcurrent curves are based on a log scale the increase in current magnitude does not correlate to the same percentage in time. Instantaneous ground over current elements are most susceptible to misoperations caused by increases in fault current, however these elements should be initially set to protect only the first 50 to 70% of the protected line based on the fault current at the remote end. With this in mind a fault current increase of 10% is not significant by itself to require

Organization	Yes or No	Question 4 Comment
		a setting review and it is very difficult to see how a 10% decrease can affect the coordination unless over current elements are the primary protection elements or over currents elements can prevent the operation of the other protection functions. If the SDT is adamant about having a periodic review of fault current levels then the time should be extended to 5 years b. and the fault current level should be increased to 20% on the protected line.
Response: Thank you for your comments. a. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.** b. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**		
Operational Compliance	No	1. We agree with the 10% value, but not with the actual wording in the Standard. The Standard reads "2.3 Where the calculation performed....indicates a deviation in Fault current of 10% or greater". It is not clear whether this means 10% Fault current deviation above or below, both or just above. 2. We also suggest that specific defined trigger events prompt a Fault current review for affected Interconnection Facilities, instead of fault current reviews being required every 24 months for every Interconnection Facility.
Response: Thank you for your comments. 1. **The drafting team changed the formula to take the absolute value of the calculated percent deviation to make it clear that the**		

Organization	Yes or No	Question 4 Comment
percent change is plus or minus 10 %. **2. Requirement 3 provides the specific defined trigger events as you suggest, however, the drafting team believes that a periodic Fault current study is still necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination.**		
Pacific Gas and Electric Company	No	The requirement to run the fault study to determine if there is any 10% change is only required once every 24 months per requirement R2.1. But if you run a batch study and find a bunch of 10% changes, you only have 6 months to do all the coordination studies. We think a 12 month window for performing the coordination studies is more appropriate.
Response: Thank you for your comment. **The drafting team believes that complying with Requirement R3 will minimize the situation you describe.**		
Western Area Power Administration	No	We have concerns over what NERC considers to be a "Protection System Study". Needs to be defined more clearly.
Response: Thank you for your comment. **The drafting team modified the description of the term "Protection System Study" in the Technical Guidelines section of the standard.**		
Independent Electricity System Operator	No	We do not agree or disagree with the 10% deviation threshold. In the Technical Justification document, the SDT indicates that "The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary." Lacking statistical or detailed studied results, this basis is as good as any. However, there does not appear to be any assessment made on the potential

Organization	Yes or No	Question 4 Comment
		BES reliability risks when the Fault current deviates by less than 10%. Many Protection Systems' settings are linked to Fault current level and as such, deviation as low as a few percent may render a Protection relay not operating as intended. We suggest the STD to assess the risk of not conducting a verification study for the Protection Systems when Fault current deviates from past values at a lower range to either confirm that a 10% deviation would be a safe trigger, or revise it according to the findings of the risk assessment. (NTD: we may also suggest that a Protection System Study should be required for every BES modification that is in the electrical proximity of the Interconnected Facility and is expected to modify the Fault current levels.)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10 % margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10 %. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.**		
Sacramento Municipal Utility District	No	1. We do not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short

Organization	Yes or No	Question 4 Comment
		circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** 2. **The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
ReliabilityFirst	No	It may be appropriate to trigger a coordination review based on multiple criteria. For instance, perhaps coordination should be verified at the interconnection at least once every 7 years, as well as whenever the available fault current at the point of interconnection changes by more than 10%. There may be other better indicators when coordination should be checked as well such as a percentage change in system impedances at the interconnecting buses. RFC also questions whether there is a justification for choosing the 10% criteria (rather than say 5%)
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Further, Requirement 3 should capture Fault current changes caused by BES additions; therefore, the drafting team believes a periodic study as you suggest is not warranted.**		
Idaho Power Company	No	No, We are unsure whether a 10% trigger level is appropriate in this context as the location of the fault is not specified in this Requirement. Faults used to properly set a

Organization	Yes or No	Question 4 Comment
		protective relay will be made at multiple locations and with various source conditions. The Requirement should be more specific in order to achieve consistent coordination among entities.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The 10% trigger will potentially initiate a Protection System Study which could involve evaluating Faults at multiple locations and with various source conditions.**		
LCRA Transmission Services Corporation	No	1. A 10% change in fault current is not an appropriate criterion or "trigger" for relay coordination review. It does not meet the standard's purpose to ensure speed and selectivity requirements associated with protection system coordination. Requirement R2 should read as follows: "For each Interconnected Facility, each Transmission Owner that has ownership of the protective relay portion of the Protection System shall: " 2. Requirement R2.2:LCRA TSC recommends not including this requirement. Requirement R2.3: Should the SDT decide to include requirement R2.2, then rephrase R2.3 as follows:"Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each non-transmission owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification. As an alternative requirement to R2.2 and R2.3, LCRA TSC recommends the following language to R2.1, 2.2 and 2.3:2.1. Perform a short circuit study to determine the present Fault current values, not less than annually. 2.2. Pursuant to Requirement R2, Part 2.1, provide summary results to each directly impacted non-Transmission Owner entity at the Interconnected Facility, within 30 calendar days after completion of the short circuit study. 2.3 Delete

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. **1. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.** **2. The drafting team believes the requirement is appropriate as written.**		
Exelon	No	1. Exelon requests that the conditions under which the required short circuit (SC) study are to be performed should be defined. What future reinforcements should be assumed in the SC model, since the result will depend on these assumptions? 2. In R2, 10% or greater deviation in Fault Current may not be adequate to perform Short Circuit (SC) Study. It should be clearly stated what threshold is adequate to perform SC study successfully, and 3. the SDT should provide some examples how the ‘six-month” time frame is considered a “reasonable amount “of time to perform the SC study.
Response: Thank you for your comments. **1. The drafting team revised Requirement R2, Part 2.1 to indicate that the maximum available Fault current values are to be calculated. It is intended that current system models are to be used when performing the 24 month calculations, not future models.** **2. The drafting team maintains that the 10% threshold is adequately sensitive and should be conducted every twenty-four months.** **3. The drafting team believes that 6 months is adequate time to perform a Protection System Study triggered by a 10% deviation in current magnitudes at an interconnection. These Protection Systems should have been previously checked and documented under a Protection System Study and any settings changes should be minor.**		
Massachusetts Municipal Wholesale Electric Company	No	MMWEC endorses the comments submitted by NPCC.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **See the response provided to NPCC's comments.**		
Public Service Enterprise Group	No	We disagree with this requirement for several reasons. a. A change in short circuit Fault current, in many cases, does not require relays to be reset. The requirement to perform a Protection System Study for this reason alone will likely provide no benefit when the relay performance is not dependent on short circuit current level. If the relay performance is directly dependent on short circuit level, then a % change in short circuit level may be appropriate. This distinction should be spelled out in R2. b. It is common for relays to be set at 30-50% of the Fault current or 150%-200% of the full load current. A change of +/- 10% in Fault current would have little to no impact on the existing settings and coordination.
Response: Thank you for your comments. **a. Requirement R1, Part 1.1.2 allows you to offer a justification as to why a Protection System Study is not needed even if Fault duty increases by 10%.** **b. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
Public Utility District No. 1 of Snohomish County	No	Comments: 1) SNPD does not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. 2) As we stated before, the results based objective is to communicate and

Organization	Yes or No	Question 4 Comment
		coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Response: Thank you for your comments. 1. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%.** 2. **The expectation is that the Transmission Owner will be reviewing short circuit values on the Transmission Owner's facilities only. When the Transmission Owner identifies a 10% deviation at a location where there are Interconnected Elements, the Transmission Owner would notify the other entity(s). The Transmission Owner is identified as the entity responsible for performing the Fault current studies because they maintain the data necessary to perform the studies.**		
Georgia Transmission Corporation	No	1) Using "V" to denote fault current values may help the non-engineer reading the document, but "I" is the common nomenclature for current in the utility industry. The equation in R2.2 should use "I" in place of "V". 2) There is a risk in using calculated fault currents of the most recent PSS and not existing relay settings. If the entity uses 10% margin in settings it will be too late to make settings changes. Should the margin be based on existing fault calculations and existing relay settings basis?
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
1. The drafting team made the suggested change replacing "V" with "I" in the equation. **2. The drafting team does not understand the scenario you describe.**		
Platte River Power Authority	No	The selection of a +/- 10% change in an Interconnected Facilty's Fault current value is arbitrary. The results based objective is to communicate and coordinate.
Response: Thank you for your comment. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
MWDSC	No	1. Every TO should not be required to perform a short-circuit study every 24 months if there were no significant changes to that TO's BES facilities. Changes in adjoining interconnected BES systems could change short-circuit duties for an adjoining TO's system. The TO whose BES changes should be responsible for performing short-circuit duties on all adjoining systems as part of Requirement R3. 2. In addition, FAC-002-1 requires TOs to coordinate with TPs and PAs in the assessments of proposed new facilities, including evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission through steady-state, short-circuit, and dynamics studies.
Response: Thank you for your comments. **1. The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.** **2. The statements you make about FAC-002-1 are correct, however, Requirement R1.4 of that standard requires the**		

Organization	Yes or No	Question 4 Comment
Transmission Owner to evaluate system performance under short circuit and other conditions in accordance with the TPL-001-0, TPL-002-0 and TPL-003-0 planning standards. The "coordination" reference in FAC-002-1 is synonymous with "cooperation". No reference to Short Circuit Studies for the purpose of verifying protective relay coordination is made in FAC-002-1. The drafting team believes that Short Circuit Studies as proposed in PRC-027 adequately accomplish the purpose of the standard.		
NPPD	No	Monitoring for a 10% change in faults could trigger studies that are not needed and it is not necessarily a good indicator settings updates are needed. It would be more practical to require a review of settings on a set interval (5 years) or as required by R3.
Response: Thank you for your comments. **The drafting team believes that a periodic Fault current study is necessary to identify incremental changes in Fault current over time that could lead to relay miscoordination. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin.**		
NextEra Energy Inc	No	It would seem that NERC Standards efforts, such as PRC-027 should focus on areas that have a record of poor performance and a contributor to misoperations. The area of tie line protection addressed in PRC-027 is not an area of poor performance, see page 4 of the attachment "....Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations". Areas that are less problematic should be addressed by NERC with less intrusive methods such as Industry Alerts, general cautionary statements or a standard with less detailed documentation requirements. Thus, PRC-027, as drafted, will unnecessarily require additional focus and resources be placed in an area that has not been a problem for the reliability of the BES. Alternatively, PRC-027 should be drafted much less prescriptively from a technical standpoint, and allow for more discretion on how to conduct the study and how to coordinate the results. The prescriptive nature of many of the technical

Organization	Yes or No	Question 4 Comment
		requirements PRC-027 is so narrow that it may counterproductive. A results-based approach here should focus more on conduct a study and coordinating the results, rather than dictating how the technical requirements of how study is to be completed.
Response: Thank you for your comments. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.**		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
National Grid USA / Niagara Mohawk	Yes	Please clarify where the fault is to be placed and where the deviation is to be observed. One possibility is to place the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to said bus.
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
SERC Protection and Control Subcommittee	Yes	a) In R2 2.2, replace the term "deviation" with "change." (Note: For this calculation, all that is required is to calculate percent change. For example, Webster's dictionary definition of "deviation" is: 1) a variation that deviates from the standard or norm; "the deviation from the mean" 2) the difference between an observed value and the expected value of a variable or function.) b) In R2 2.2, replace the term "present" with "new" and the term "most recent" with

Organization	Yes or No	Question 4 Comment
		"previous". Also reflect this terminology change in the %Change equation. (The use of the terms "present" and "most recent" can be perceived to be the same.) c) It is also recommended that "V" for value be replaced by "I" for current. d) In R2 2.1, please add "new", delete "present" and add either "under normal conditions" or "maximum system conditions" so that it states "Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
Response: Thank you for your comments. **a. The drafting team believes that the term "deviation" is properly used in R2 Part 2.2 and is synonymous with the term "change".** **b. The drafting team believes that the terms "present" and "new" are properly used in R2 Part 2.2 and are synonymous with your recommended changes.** **c. Per your suggestion, the drafting team has modified the equation to replace "V" with "I".** **d. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Associated Electric Cooperative, Inc., JRO00088	Yes	1. A 10% threshold seems simple, but the SDT may or may not wish to clarify the formula to be applied because any of the following is a valid interpretation: 1) abs(Vscs - Vpss)/Vscs, 2) abs(Vscs - Vpss)/Vpss, 3) abs(Vscs - Vpss)/0.5(Vscs + Vpss), 4) abs(Vscs -Vpss)/Max(Vscs,Vpss), or 5) abs(Vscs-Vpss)/Min(Vscs,Vpss). 2. Also see SERC PCS Comments.
Response: Thank you for your comments. **1. Initially, the posted standard was missing the equation but the document was reposted with the equation included. The drafting team modified the equation to include the absolute value.**		

Organization	Yes or No	Question 4 Comment
2. Please see the drafting team's responses to the SERC PCS comments.		
Southern Company	Yes	When calculating the "+/- 10 % Fault current threshold", the use of bus fault values vs the line contribution values should be clarified.
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Texas Reliability Entity	Yes	1. Using a +/- 10% change is a good threshold, with the understanding that if a change in fault current value of less than 10% results in a need to change relay settings, then Requirement R3.1 will cover the coordination between entities in that case. 2. Additional comment: For R2.1, Does the SDT also want to consider other system studies in addition to short circuit studies (e.g. critical clearing time studies at generation facilities needed for breaker failure coordination, equipment rating studies, or stability studies)?
Response: Thank you for your comments. **1. Your understanding about R3.1 covering the scenario you describe is correct.** **2. The drafting team doesn't believe that the other studies you mention should be considered in this standard.**		
Xcel Energy	Yes	Similar comments on measure M5 as contained in item 3 above on measure M2.This provision should become effective 36 months after the effective date of the standard.
Response: Thank you for your comments. **The drafting team believes that the description of the evidence in the Measure is acceptable. The drafting team further believes**		

Organization	Yes or No	Question 4 Comment
that the 24 month time frame to perform a short circuit study is adequate.		
Ameren	Yes	(1) In R2 2.1 we request the SDT add “under normal conditions” or “under maximum system conditions” so that it states “Perform a short circuit study to determine the present Fault current values under normal conditions, not less than once every 24 months. “ (2) We request the SDT clarify which Interconnection Facility fault current values are to be compared. If the intent is to keep this general so the entities have the flexibility to compare those fault current values that the entities judge appropriate, please state. Otherwise we suggest adding “Specifically find fault current values flowing into each terminal of the Interconnected Facility for independently applied single line to ground and 3-phase short circuits at its other terminal(s).” (3) We request the SDT change R2 2.2 wording to “Calculate the percent [delete - deviation] change between the Fault current values (single line to ground and 3-phase [delete - for the bus(s) or Element(s)] flowing into each terminal of the Interconnected Facility under consideration) used in the most recent Protection System Study...”. This along with our recommended change to R2 2.1 clarifies the short circuit values that are to be compared. (4) We request the SDT change R2 2.1 to “not less than once every 5 years” for consistency with TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. Our experience is that PRC-027-1 R3 will trigger almost all Protection System Studies anyhow.
Response: Thank you for your comments. 1. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”** 2. **The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**		

Organization	Yes or No	Question 4 Comment
where a Protection System Study is available per Requirement R1." **3. The drafting team believes that the term "deviation" is properly used in R2 2.2 and is synonymous with the term "change". We also believe that the changes made to R2.1 clarify where the fault is to be applied and monitored.** **4. The reliability intent and purpose of the two standards is different. The drafting team agrees with you that Requirement R3 should capture Fault current changes caused by other BES additions.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	Ingleside Cogeneration LP agrees that a 10% delta in Fault current is material and would warrant further study. However, we are not sure how these studies would correlate to those managed by Planning Coordinators and Transmission Planners. It seems like these entities would have to be involved in any studies that may result in a change in relay settings or a Protection System upgrade.
Response: Thank you for your comment. **The drafting team does not believe the Planning Coordinators or Transmission Planners need to be involved in Protection System Studies associated with verifying protective relay coordination.**		
American Transmission Company	Yes	ATC does agree with the premise of the a 10% change but believes that the SDT needs to provide a clear definition of which fault current must change 10% to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in feed current and relay settings.
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	However it's unclear what Fault duty is being referred to. Is it the total Fault current at the bus, or Fault current that flows down the line or to the generator? It should also be clarified that Fault duty is the normal case (i.e. with all sources and all lines in-service).
Response: Thank you for your comment. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."**		
Oncor Electric Delivery Company LLC	Yes	Oncor takes the position that the 10% fault current threshold criteria is the only criteria needed;
Response: Thank you for your comment.		
Dominion	Yes	a) In R2-2.2 Replace the term "deviation" with "change". {(Note: For this calculation all that is required is to calculate percent change. i.e. Webster's dictionary definition of "deviation" is 1) A variation that deviates from the standard or norm; "the deviation from the mean". 2. The difference between an observed value and the expected value of a variable or function. This is not a statistical calculation.) } b) In R2-2.2, Replace the term "present" with "new" and the term "most recent" with "previous". c) Change the % Deviation Equation to % Change. Reflect as stated above in the equation legend (the use of the terms "present" and "most recent" can be perceived to be the same). d) Replace "V" (Value) with "I" (Current) in the % Change Equation. "V" is frequently used to represent Voltage and this could lead to confusion. e) In M5 Replace the term "deviation" with "change".

Organization	Yes or No	Question 4 Comment
		f) In R2-2.1 please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it states “Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.
Response: Thank you for your comments. a. The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”. b. The drafting team believes that the terms “present” and “new” are properly used in R2 Part 2.2 and are synonymous with your recommended changes. c. See response to “a”. d. Per your suggestions and others, the drafting team has modified the equation to replace “V” with “I”. e. See response to “a”. f. The drafting team modified Requirement 2.1 to read “At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1.”		
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Luminant	Yes	
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 4 Comment
Western Small Entity Comment Group	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	
Salt River Project	Yes	
American Electric Power	Yes	
Flathead Electric Cooperative, Inc.	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Tri-State G & T	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 4 Comment
Company		
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
CenterPoint Energy	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
MRO NSRF		1. The NSRF recommends that a clear definition of what fault current must change 10 % to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in-feed current and relay settings. 2. It would be easier to implement a time-based periodic review of settings every 5 - 8 years (or sooner if required by conditions in Requirement R3). 3. R2 is redundant and could subject entities to double jeopardy in conjunction with the new TPL standards which will require annual short circuit studies and NERC studies should not be duplicated to avoid double jeopardy. 4. At a minimum, the 24 month requirement should be changed to at least every 2 calendar years. This would align with the annual requirement for the TPL standards. The new TPL standards are in limbo with FERC's rejection to footnote b.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **1. The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** **2. The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. Entities are not precluded from notifying other entities at levels of Fault currents lower than 10%. The drafting team did not make any of the suggested changes. Further, Requirement 3 should capture Fault current changes caused by BES additions.** **3. The requirements in the two standards are different and therefore not redundant.** **4. The drafting team disagrees and believes that the 24 month frequency is adequate.**		
El Paso Electric Company		It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: o Study performed in Year 1 shows a 5% deviation o Study performed 12 months later (in Year 2) shows a 5% deviation o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Response: Thank you for your comment. **The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after**		

Organization	Yes or No	Question 4 Comment
the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.		
El Paso Electric		It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: o Study performed in Year 1 shows a 5% deviation o Study performed 12 months later (in Year 2) shows a 5% deviation o Study performed 12 months later (in Year 3) shows a 5% deviation[Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Response: Thank you for your comment. **The intent is to capture cumulative changes over time and perform a new Protection System Study when the 10% threshold is reached. The starting point is the most recent Protection System Study in which the relay settings were established or verified. At least every two years after that, a new Short Circuit Study is performed and the new short circuit values are compared to the short circuit values from the original Protection System Study. In your example, a new Protection System Study would be triggered after the Short Circuit Study in year 2 when the cumulative 10% deviation occurred.**		
mason		No comment

5. **In Requirement R3, the SDT included a list of proposed changes that impact the coordination of Protection Systems and would initiate a need to inform other entities. Do you agree that this is an appropriate and inclusive list? If not, please provide specific suggestions for additions or deletions with your reasoning(s) in the comment area.**

Summary Consideration:

Several commenters suggested minor wording changes to the list included in Requirement R3, Part 3.1. The drafting team considered all of the suggestions and made changes including combining the second and third bullets to read as follows 'Changes to a transmission system Element that change any sequence or mutual coupling impedance'. Also, the fourth and fifth bullets were modified to indicate that impedance changes are what need to be communicated.

A few commenters had concerns with the 30 day time frame in Parts 3.2 and 3.3 while other commenters wanted them eliminated. The drafting team explained that they believed the 30-day time frame is appropriate and declined to make the change, and further explained the purposes for the Parts and retained them with minor wording changes.

Some commenters wanted to remove reference to schedules in the requirements. The drafting team reinforced that they believe the sharing of project schedules is a necessary communication between entities.

Some commenters did not like the use of the word "error" in Requirement 3, it was restated as follows: Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.

A few commenters expressed concerns that there is redundancy between this draft standard and several FAC standards. The drafting team stated their belief that these concerns were not applicable.

Organization	Yes or No	Question 5 Comment
Southwest Power Pool NERC Reliability Standards Development Team	No	In R3 we would suggest that re-rating could be use as a temporary procedure which is addressed in the TOP standards and if the drafting team needs to include these types of re-ratings that they be more specific to exclude the temporary re-ratings. Changes to generator unit(s), including replacements, Output change that causes a change in the protection system, and impedances

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment **The drafting team believes that if a temporary or permanent re-rating modifies the conditions used in the coordination of Protection Systems of the Interconnected Stations, then any associated protective relay setting changes must be provided to the other entities.**		
Pepco Holdings Inc. & Affiliates	No	The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2:R2.1 – 1. Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. 2. R2.2 - Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..."The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". 3. Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each "element under consideration" used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and

Organization	Yes or No	Question 5 Comment
		comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a "batch" screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 "Additions, removals, or replacements of transmission Elements".
Response: Thank you for your comments. **1. Per your suggestions and others, the drafting team has modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** **2. The drafting team believes the existing wording was sufficient and did not make your suggested change.** **3. The drafting team did remove the word "or Element(s)" as you suggested.**		
Hydro One	No	While we agree with the principle of exchanging information, R3.1 is confusing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." We believe that this statement is too inclusive. It implies that changes in facilities other than the Interconnected Facility need to be communicated and is too open for interpretation. Suggest the scope be better defined and limited only to changes at the Interconnected Facility.
Response: Thank you for your comment **The drafting team revised the term "Interconnected Facilities" to "Interconnected Element". The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near**		

Organization	Yes or No	Question 5 Comment
Interconnected Elements that could require a change in impedance relay settings for overreaching zones.		
Luminant	No	Luminant agrees with R3.1 and 3.2. Luminant suggests that the language in this requirement be revised so it is clear what is to be provided between the parties.
Response: Thank you for your comment. **Requirement R3, Parts 3.1, 3.2, and 3.3 each refer back to the main Requirement R3. The drafting team revised Requirement R3, Part 3.2 to clarify that it pertains to responses for Protection System coordination information.**		
Bonneville Power Administration	No	BPA believes that it is not practical to list all of the possible changes that could impact the coordination of protection systems. Any such list will likely lead to unnecessary notification in most cases, while failing to recognize unusual situations that could cause miscoordination. BPA is in favor of a simplified approach where notification is provided to the owner of the remote terminal(s) whenever a change is made to the protection scheme at one terminal.
Response: Thank you for your comment. **The drafting team appreciates your concern but believes changes to a protection scheme are not the only system changes than can lead to miscoordination.**		
FirstEnergy	No	Requirement 3, Part 3.1 - We believe that some entities registered as both a TO and a GO may face Standards of Conduct issues if a TO is required to provided the “bulleted” data specified within the Part 3.1.
Response: Thank you for your comment. **The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.**		
Santee Cooper	No	In R3, 3.3.1, change the wording to address “changes” instead of “corrections” for “errors.” Many changes are made that are not the result of errors. The purpose here

Organization	Yes or No	Question 5 Comment
		should be to communicate changes, and people shouldn't have to debate whether or not to make an "improvement" (not because of an error or misoperation) because it may be construed as a correction of an error.
Response: Thank you for your comment **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Western Small Entity Comment Group	No	R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.
Response: Thank you for your comment. **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		
Northeast Power Coordinating Council	No	DP must be excluded from R3. See the response to Question 2.
Response: Thank you for your comment **The drafting team believes that the Owner of the Protection System is responsible for sharing information to ensure its Protection Systems are coordinated with others.**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
The drafting team revised the term "Interconnected Facilities" to "Interconnected Element". The drafting team believes that coordination is required at all Interconnected Elements between Transmission Owners and Generator Owners regardless of whether the entity is an independent Generator Owner. It is acknowledged that in many cases, the majority of the work associated with this task will fall on the Transmission Owner; however, the coordination of some Protection Systems applied on generators must be verified by the Generator Owner.		
SERC Protection and Control Subcommittee	No	a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3 3.3.1, change requirement to read: "Changes are made to a Protection System as a result of findings during misoperation investigations, commissioning, or maintenance activities."(The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this requirement needs to be placed on "changes" made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)
Response: Thank you for your comment. **a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.** **b. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Colorado Springs Utilities	No	Specific project schedules can potentially cause violation of other requirements. 1. A proposed change of conductor spacing, which can be interpreted as a change of one transmission structure requires notification to other entities, which we feel is excessive. 2. Re-rating of generators rarely changes the protection, impedances or coordination involved. It is common to re-rate units depending on external factors to the

Organization	Yes or No	Question 5 Comment
		generator which also provides excessive reviews and project schedule notifications. 3. This section also implies notifications must be made after like and kind replacements of equipment found during misoperation investigations, but not those found during testing. On larger systems this requirement would be difficult unless notifications were made more than twice a month, which would require a large tracking system of who, what, and when information is sent to interconnected utilities.
Response: Thank you for your comment 1. **The drafting team has modified the bullet in 3.1 to read "Changes to a transmission system Element that changes any sequence or mutual coupling impedance'; therefore, the noted change in spacing that does not change the impendence used in the system model would not need to be communicated.** 2. **The drafting team believes that, regardless of the probability of a change affecting Protection Systems; it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.** 3. **The drafting team believes that testing is included in commissioning and maintenance activities. The drafting team believes that relay replacement information needs to be provided to the interconnecting entity and that 30 calendar days is sufficient and adequate to provide the notice.**		
Tennessee Valley Authority	No	a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3,Part 3.3.1, change Requirement to read: "Changes are made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities." (The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this Requirement needs to be placed on "changes" made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. a. **The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party.** b. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Associated Electric Cooperative, Inc., JRO00088	No	1. AECI believes the industry would be better served by placing this list of items into a Guidance document, and rephrasing R3 to include only "field-changes known to modify the conditions used in coordination settings of Protection Systems." Although some of the listed items are direct-impact, as currently drafted, any field-equipment changes are potentially in scope, regardless of proximity to the Interconnected Facility(s) of interest. 2. With exception of R3.1 Bullet #1, the R2.3 10% is a better metric and the other Guidance bullets and wording we proposed above, should be added into R2.3.
Response: Thank you for your comment 1. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 2. **The drafting team respectfully disagrees and declines to make your suggested changes.**		
ACES Power Marketing Standards Collaborators	No	In general, we are supportive of the list and requirement because it helps to clarify what changes are intended in Part 1.1.3 in Requirement R1. However, we have identified two specific issues with the list. (1) First, we question if this requirement is at least partly duplicative with FAC-001-0 R2.1.2 which requires the TO to have procedures for notification of new or modified equipment.

Organization	Yes or No	Question 5 Comment
		(2) Second, the third bullet regarding additions, removals, and replacements of transmission system Elements is too broad. This literally means that if a TO replaces a bus section with similar equipment, this requirement to notify of changes is triggered which then triggers a Protection System Study or documentation that one is not required per Requirement R1 Part 1.1.3. Ultimately, we believe the changes that need to be identified are those that actually affect the Protection Systems for the Interconnected Facilities or those that change the Fault current on the Interconnected Facilities. (3) The 30 day requirement should be struck from Part 3.2. If a schedule is not identified by any party, it must not be pressing and an artificial deadline should not be created. (4) The language of the main requirement needs to be further refined. A literal reading would require the TO, GO, and DP to provide details about Interconnected Facilities that they neither own nor operate or to which they are even connected. Obviously, the literal meaning is not intended. The requirement needs to be refined to clarify that the TO, GO, and DP only need to provide the details for Facilities they own. (5) For Part 3.3.2, we suggest clarifying that this requirement does not apply if the equipment is replaced with like equipment and settings. (6) We also suggest that that some sort of exemption is written into this part for extreme weather events that allows more time for notifications.

Response: Thank you for your comment

1. **While FAC-001 Part R2.1.2 does require the Transmission Owner to have a procedure, the drafting team believes the two requirements are not duplicative. PRC-027-1 Requirement R3 requires the communication of Protection System information between owners of Interconnected Elements.**
2. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be**

Organization	Yes or No	Question 5 Comment
communicated. **3. The drafting team believes that 30 days is a sufficient time to reply to a request for information; however, the requirement provides flexibility to negotiate an extended schedule.** **4. The drafting team revised Requirement R3 for clarification, indicating that the owner shall provide details to only Responsible Entities connected to the same Interconnected Element.** **5. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."** **6. The drafting team believes that 30 calendar days is sufficient and adequate to provide the notice and declines to make a change.**		
Kansas City Power & Light	No	Bullet item #3 is too broad. The NERC Glossary definition for Element is, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.". For example, a disconnect switch would be considered an Element, but a change of this component would not warrant a change to relay protection. Recommend modifying bullet item #3 to, "Additions, removals, or replacements of transmission system Element(s) that have an impact on relay protection systems or component(s)"
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Southern Company	No	Reference the bullet on Line items; the issue of mutual coupling and/or overhead grd wire replacement or changes should be included. Perhaps change to any change that impacts the positive, or zero sequence impedance.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **Based on your and other comments, the drafting team revised Requirement R3 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
Western Area Power Administration	No	1. What are the details to be provided? 2. Should only be for significant changes.
Response: Thank you for your comment **1. The drafting team believes that the examples of the provided information are clear but leave flexibility between the two parties.** **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Flathead Electric Cooperative, Inc.	No	Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward
Response: Thank you for your comment **Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.**		
Manitoba Hydro	No	(1) It is not clear what this list should include. Should the protection changes on the interconnected facilities only be included? Or should it include the protection

Organization	Yes or No	Question 5 Comment
		changes on the adjacent elements? (2) Also, for the changes of power system elements, should those connected directly to the interconnecting bus be included or it should also include changes beyond that?
Response: Thank you for your comment **1. The drafting team believes Protection System changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues.** **2. The drafting team believes changes at other Facilities that modify the conditions used in the coordination of Protection Systems of the Interconnected Elements need to be communicated because they could lead to coordination issues. An example of this is a new substation installed near Interconnected Elements that could require a change in impedance relay settings for overreaching zones.**		
LCRA Transmission Services Corporation	No	(1) Requirement R3 should read: Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall provide to each directly impacted Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: (2) The first bullet of requirement R3.1 should read: New installation, replacement with different types, or modification of: protective relays or protective function settings that result in a direct impact on protection system coordination to an entity at that Interconnected Facility. (3) The second bullet of requirement R3.1 should read: Changes to positive or zero sequence line impedance by more than 5 percent
Response: Thank you for your comment **1. The drafting team believes that the Applicability section appropriately describes which entities and for which installations**		

Organization	Yes or No	Question 5 Comment
require exchange of data. **2. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. (3) Based on your comment and others, the second bullet of Requirement R3, Part 3.1 was modified (and combined with the third bullet). However, the drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Exelon	No	In the current draft of PRC-027-1, Requirement 3.1 mandates that for any of the listed network changes, entities must communicate "the details", (i.e., design information to all entities that share the interconnection). Of the network changes/additions listed in the draft, however, some may result in little or no changes to existing protection system coordination settings, thereby having no impact to Protection Systems of other entities. For example, consider a project by a TO to replace a BES circuit breaker at an Interconnected Facility. Assume that breaker failure protection for that circuit breaker will also be upgraded, but that the settings and all protection functions for the new relay remains unchanged from the old system. According to the language of Requirement 3.1, the TO would be required to transmit design information to other entities associated with the interconnected facility even though the project would have no impact to the other entities. This represents one example of a frequently performed project in which design information is not presently shared between entities at an Interconnected Facility. Mandatory compliance with this requirement, as written, could represent a significant burden to the industry by requiring unnecessary communication of design details to other entities, in addition to the added compliance documentation activity, and having no impact to protection systems of the recipients. Exelon suggests that the SDT clarify Requirement 3.1 such that that if a change to an Interconnected

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>Facility is not expected to result in a change to the desired sequence of Protection System operations , the compliance activities required by R3.1 should be waived</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.

In your specific example, the drafting team believes that, if the proposed breaker failure protection change does not modify the impedances used in the calculation of fault currents, then the information does not need to be exchanged.</td></tr>
<tr><td>Tacoma Power</td><td>No</td><td>1. This list does not appear to sufficiently address BES transformers (e.g., autotransformers).

2. There is concern that R3.1 may introduce either an administrative burden to identify and track every change, including those that would not reasonably impact Protection System coordination, or compliance jeopardy if those changes are not identified and tracked.

a. For example, the second bullet under R3.1 refers to changes to line spacing. Assume that, during restoration following a Fault, a damaged insulator on one pole or tower is replaced with an insulator one inch longer. Technically, this changes the line spacing. It is doubtful that the SDT intended that this or a similar but less trivial scenario would trigger a Protection System Study; however, the language may introduce compliance jeopardy. Perhaps a similar metric as used in R2.3 could be applied to the second, third, fourth, and fifth bullets. For example, perhaps a 5% change in interconnecting Element impedance from a baseline could trigger a Protection System Study; this approach could be used in lieu of the second and fifth bullets. It seems that R2.3 would address the third and fourth bullets if the short circuit study were conducted before the change was implemented.

b. Additionally, the language in the first bullet under R3.1 may introduce compliance jeopardy. For instance, it is possible for an entity to adjust a current and/or voltage</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		transformer ratio and compensate with one or more relay settings such that the primary settings do not change. In many of these cases, there will be no impact on Protection System coordination. While active communication among entities is advised, the potential for fines in this type of scenario does not seem to be appropriate. The emphasis on the first bullet under R3.1 should be on Protection System scheme (e.g., distance, overcurrent, DCB, POTT, differential), primary settings (including time delays), independence/redundancy, and technology (primarily for communications systems).
Response: Thank you for your comment **1. The drafting team believes that BES transformers are addressed in the original third bullet, which is now combined into the second bullet, of Requirement R3, Part 3.1.** **2a. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, the drafting team believes that the type of damage replacement that you suggested is so small that it would not modify the impedances used in the calculation of fault currents and would therefore not need to be communicated to the interconnecting entity. Part 3.1 does not trigger a Protection System Study.** **2b. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the type of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
Public Service Enterprise Group	No	a. R3 should be rewritten as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the following to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility:” b. Part 3.1 should be modified as follows: “For any change or additions listed below,

Organization	Yes or No	Question 5 Comment
		provide a project schedule and the reason for the project, whether to an existing or new Interconnected Facility or to other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities:" c. Part 3.2 does not read well and is not supported by the explanation in the text box. It references 1.1.1, 1.1.2, and 1.1.3, but none of these parts allow an Interconnection Facility owner to request information from another owner to perform the Protection System Study. We can understand why Interconnection Facility owners need to cooperate in the performance of such studies. This thought belongs in R1. We suggest a new 1.2 (with the existing 1.2 renumbered to 1.3) as follows: "Each Interconnected Facility owner shall provide data requested by another owner and which is needed to perform the study in 1.1, either in accordance with an agreed-upon schedule, or within 90 days of receiving the request." We believe 30 days is too short to require a response.
Response: Thank you for your comment a. **Requirement R3 was reworded to enhance clarity.** b. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** c. **The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that 30 calendar days is sufficient and adequate to provide the response, and declines to make a change.**		
Liberty Electric Power LLC	No	The phrase "Changes to generator unit(s), including replacements, re-ratings, and impedances" is too vague. Audit teams could read any change as a trigger. Suggested change: "following the replacement or re-rating of a generator, or following any change to a generator which results in a change in impedance".

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The drafting team has made your suggested change.**		
Ameren	No	We recommend the following changes to Requirement 3- (1) Include 'static wire' in the second bullet, or more simply state as 'line impedance changes.' (2) Include 'bus arrangement changes' in the third bullet. (3) Change the fourth bullet to include 'Additions, retirements, or changes...' to strive for consistency for generation and transmission.
Response: Thank you for your comment **1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** **2. The drafting team believes that "bus arrangement changes" would be included in the revised second bullet of Requirement 3, Part 3.1.** **3. The drafting team believes the existing language is clear with regard to generation and respectfully declines to make the change.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	Ingleside Cogeneration LP believes that the coordination process developed by the project team is redundant with the one established in FAC-002-1. If there is a material change made to a Facility, the process should be captured in a single reliability standard.
Response: Thank you for your comment. **FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the "Description of the Current Draft," PRC-027 is replacing PRC-001, Requirements R3 and R4.**		

Organization	Yes or No	Question 5 Comment
Georgia Transmission Corporation	No	1. The parenthetical comment in R3 should be deleted. R3.1 lists the items that would trigger the need for notification between entities. Once notified of modifications, the entities will communicate documentation needs. 2. R3.2: In the case of major BES equipment failure, there is a more pressing need to notify an interfacing entity that there has been change that could affect fault magnitudes. The 30 calendar days may be too long for such occurrences and 2 business days would be more in consideration. 3. R3.3.1 may interfere with PRC-004-# time schedules for misoperation follow-ups and investigations. 4. R3.3.2: Refer to comment above regarding R3.2.
Response: Thank you for your comment **1. The drafting team believes that the parenthetical expression is beneficial to Requirement 3, but it was moved to Part 3.1 for clarity.** **2. Requirement 3, Part 3.2 regards responding to a request for information required to perform a Protection System Study, not for notification of an unplanned change in the BES configuration.** **3. The drafting team believes that the notifications of Requirement 3, Part 3.3 will not impact schedules for any future version of PRC-004 because the notifications take place after the corrective action has been implemented.** **4. Requirement 3, Part 3.2 regards the failure of Protection System components and their replacement, not BES Elements that can change the fault duty.**		
Wisconsin Electric Power Company	No	1. R3 should have the phrase “shall notify...” in the requirement, not simply “shall provide ...the details”. This should be a requirement for entities to provide a notification to other entities that some changes are being planned which may affect Protection System coordination. 2. The wording in R3.1 is unclear as to the intended scope of the qualifying phrase, “when the proposed change modifies the conditions used in the coordination of

Organization	Yes or No	Question 5 Comment
		Protection Systems of the Interconnected Facilities." It should be made clear that ONLY those changes which affect coordination need to be communicated to other entities, whether at new or existing Interconnected Facilities or other facilities. If this is the case, then some of the comments below may not apply. 3. Also in R3.1, the bullets for "changes" in transmission systems and generators should be modified by the word "significant". Likewise, a "replacement" of an Element, or relay, or other device, may not require any change in relay settings, so the wording should be modified by "replacements which require protection setting changes". The bullet for changes to generators should also remove the "re-ratings" term, since a re-rating of a generator typically affects output power, but does not change the impedance. Indeed, there may be many minor changes which fall in the current R3.1 list which may have little or no effect on fault coordination, and therefore should not trigger a requirement for a notification or a study. Also, changes to CT or VT ratios do not necessarily result in a change in primary quantities, so these references should be removed. 4. R3.2 should be revised to require an entity making significant changes to provide the data to the other affected entities, without the need for the other entities to request it. 5. The R3.3 requirement (3.3.1 and 3.3.2) to notify other entities within 30 days for changes made following a Misoperation or failure is too restrictive. A timeframe of 60 days would be more appropriate. Also, as above, these requirements should only be applicable when the changes made have a "significant effect on coordination." A requirement to make notifications for changes unrelated to Interconnected Facility coordination will not serve the objective of increased reliability, and only increases unnecessary compliance documentation. 6. M7 (last phrase) should be revised to "...or absent such an agreement, within 30 calendar days of a request."
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
1. **The drafting team believes that providing the details of the changes is more beneficial than just notifying of a proposed change.** 2. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 3. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 4. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** 5. **The drafting team believes that 30 days is a sufficient time to reply to provide the information on the changes.** 6. **Based on your comment, Measure M6 (old M7) was modified to read, "Acceptable evidence for R3, Part 3.2 is dated documentation (hard copy or electronic file formats) demonstrating the requested information was provided according to the agreed-upon schedule, or absent such an agreement, within 30 calendar days of a request."**		
Lincoln Electric System	No	LES is concerned with the significant amount of data and information an entity would be required to share as part of R3. As an example, if a CT ratio on a secondary relay with no pilot tripping is changed, but does not change the intended response of that relay, then there is no reason to share that information simply for the sake of sharing it. Entities should be allowed some amount of discretion regarding the information to be shared amongst other entities.
Response: Thank you for your comment **The drafting team believes that communication between interconnecting entities is important for any change that modifies the**		

Organization	Yes or No	Question 5 Comment
information previously used to comply with Requirement R2, regardless of the type of change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.		
Portland General Electric Company	No	No, Add facility ratings and define transmission line impedance tolerance (see question 9 response)
Response: Thank you for your comment. **The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary. Your concern relating to PRC-023 is valid and may need to be addressed in FAC-009 or PRC-023.** **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.**		
American Transmission Company	No	ATC does not agree with the list as written and recommends the following changes: (1) ATC suggests that Requirement 3.1 bullet 2, be revised as follows: Changes to line lengths and/or conductor size or spacing that result in significant impedance changes. As an example, an interconnected line may need to relocate a pole because of a road move. This may alter slightly the length or spacing of the line but does not result in a change to the impedance. If no impedance change occurred, no relay settings need to be changed and there should be no additional coordination. (2) ATC suggests that Requirement 3.1 bullet 3, be revised as follows: Additions, removals, or replacements of transmission system Element(s) that is significant. An Element may be replaced with an equivalent device that does not require a relay setting change. If no relay settings need to be changed, there should be no additional coordination.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment 1. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, since the impedance did not change the drafting team believes you would not need to inform each Responsible Entity connected to the same Interconnected Element.** 2. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.**		
NPPD	No	Section 3.3 should clarify if the corrections change the coordination then other entities should be notified.
Response: Thank you for your comment **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Utility Services	No	This requirement if left as is, would create a potential double jeopardy situation if a violation occurs. Under FAC-002, entities already have the obligations to communicate and coordinate the integration of new, replacement, or upgrades on existing facilities. We view this requirement to be a duplication of that standard and creates a double jeopardy situation if a violation were deemed to have occurred.
Response: Thank you for your comment **FAC-002-1 does not address Protection System coordination and the drafting team does not believe the two standards are redundant. As described in the "Description of the Current Draft," PRC-027 is replacing PRC-001, Requirements R3 and R4.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>mason</td><td>No</td><td>Do not agree with blanket inclusion of replacement of the generator step-up transformer(s) on this list.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. It is the experience of the drafting team that modeling information will change with the replacement of a transformer.</td></tr>
<tr><td>Illinois Municipal Electric Agency</td><td>No</td><td>Illinois Municipal Electric Agency (IMEA) recommends language be included in R3 (and elsewhere if needed) to clarify the R3.1 "generator unit(s)" is not applicable to a 20 MVA or less unit or behind-the-meter generation.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment

This is an issue that reaches beyond the scope of this standard and may need to be addressed through a Request for Interpretation. However, the Applicability section indicates that an entity that is registered as a Generator Owner and has Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements will need to comply with this standard.</td></tr>
<tr><td>Trans Bay Cable</td><td>No</td><td>Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment

Requirement R2 requires the Transmission Owners to perform the Fault current studies because they have the necessary information to perform the studies. Requirement R1 requires all applicable entities to perform Protection System Studies. Requirement R3 requires all applicable entities to exchange the information necessary for Protection System coordination.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	No	(a) Requirement 3 includes providing schedule information and project details to generation entities. There may be established market rules that provide for what information can be shared with competitive entities. (b) Requirements 3.1 and 3.3, with examples of what system and equipment changes require coordination, appear overly broad. Such requirements should only be "if applicable". R3.1, for example, specifies changes in line length. Certain changes of line length are immaterial to protection system set points. (c) R3.3 requires coordination for the replacement of failed equipment. Replacing equipment "like function-for-like function" should be excluded from this requirement.
Response: Thank you for your comment a. **The drafting team does not believe that the requested exchange of information would violate the Standards of Conduct for an entity registered as both a GO and a TO.** b. **The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available.** **In your specific example, the drafting team believes that the entities involved can agree whether the change is significant enough to warrant an immediate review of the Protection System or whether the change could just be added to the simulation model for review as a part of the fault current assessment specified in Requirement R2.** c. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Duke Energy	No	(1) Revise second bullet under R3.1 as follows: "Changes to line impedance". (2) Add another bullet under R3.1 as follows: "Changes to breaker failure scheme

Organization	Yes or No	Question 5 Comment
		operating times”. (3) Also, we don’t agree with the R3.1 Rationale that specifying a single time frame is inappropriate. A time frame similar to R3.2 should be specified. We suggest the following revised lead-in paragraph to R3.1: “According to an agreed-upon schedule or absent such an agreement, 180 calendar days prior to implementing any change or additions listed below; either at an Interconnected Facility or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities”.
Response: Thank you for your comment 1. **Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated.** 2. **The drafting team believes that breaker failure scheme timers are already included from the first bullet.** 3. **The drafting team respectfully disagrees and declines to make your suggested changes.**		
South Carolina Electric and Gas	No	R3.3 in its entirety should be removed considering that all conditions covered by R3.3 are already covered by R3.1 which states: “New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios” If a correction or replacement of a protection system element is made per R3.3, this is the same thing as a modification covered under R3.1. It is noted that R4 would need to be reworded to accommodate unplanned and emergency protection system changes.
Response: Thank you for your comment **The purpose of Requirement R3, Part 3.3 is to allow retroactive notification when changes are made during events such as commissioning or component failure.**		

Organization	Yes or No	Question 5 Comment
ExxonMobil Research & Engineering	No	
Sacramento Municipal Utility District	Yes	(1) We agree with the list in R3.1. (2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.
Response: Thank you for your comment 1. **Thank you for your support.** 2. **Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Public Utility District No. 1 of Snohomish County	Yes	(1) Comments: SNPD agrees with the list in R3.1. (2) We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state - replacing a failed relay like for like.
Response: Thank you for your comment 1. **Thank you for your support.** 2. **Requirement 3, Part 3.2 is associated with providing information required to perform Protection System Studies, which may be required outside of a change in 3.1. Based on your and other comments, the drafting team revised Requirement R3, Part**		

Organization	Yes or No	Question 5 Comment
3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
Dominion (this vote was changed to No, per Connie Lowe's email with updated comment submission)	No	a). Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout the draft already address notification requirements. By using the term project scheduling this implies that detailed project information needs to be included in the information exchange. The standard should not dictate the information exchange details required and should allow the entities to determine what information is required in the exchange in order to achieve protection coordination in the appropriate timeframe. b). In R3 reword to read: "Each Functional Entity shall provide to other Functional Entities connected to an Interconnected Facility, the details of the Protection System as follows:" (It is not necessary to include (e.g. Examples) since references to these are already listed in R3-3.1.) c). In R3-3.1 reword to read: "When adding new or modifying existing Interconnected Facilities or when making changes to other facilities where the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities" d). Bullets: 1st bullet -Recommend changing reference to "protective Function settings" to "protection settings"./ 2nd bullet – Reword to read: "Line impedance changes" / 3rd bullet – Remove the word "system" e). In R3-3.3.1 change Requirement to read: "Changes found during Misoperation, commissioning, or maintenance activities that modify the conditions used in the coordination of Protection Systems. "
Response: Thank you for your comment		

Organization	Yes or No	Question 5 Comment
a. The drafting team believes it is necessary to share the pertinent scheduling information that could affect the other party. b. The drafting team believes the current wording more correctly states the requirement. c. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2, regardless of the magnitude of the change. This will ensure that the cumulative effect of multiple small changes will be included in the calculations to develop fault currents and ensure that the information to perform Protection System Studies is available. d. The drafting team believes the first bullet accurately portrays the requirement's needs. e. Based on your and other comments, the drafting team revised Requirement R3, Part 3.1 by combining the second and third bullets and modifying the language to state that only changes that affect the sequence or mutual coupling impedance must be communicated. f. The drafting team combined the 3rd bullet of Requirement R3, Part 3.1 with the 2nd bullet but the drafting team did not believe that "system" needed to be removed. g. Based on your and other comments, the drafting team revised Requirement R3, Part 3.3.to read: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
National Grid USA / Niagara Mohawk	Yes	
Imperial Irrigation District (IID)	Yes	
Detroit Edison	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 5 Comment
Salt River Project	Yes	
Operational Compliance	Yes	
Pacific Gas and Electric Company	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Texas Reliability Entity	Yes	
Xcel Energy	Yes	
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	

Organization	Yes or No	Question 5 Comment
ATCO Electric	Yes	
El Paso Electric Company	Yes	
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
El Paso Electric	Yes	

6. In Requirement R4, the SDT required that agreement must be reached prior to implementation of proposed Protection System changes except under the conditions identified in Requirement 3, Part 3.3. Do you agree with this need? If not, please specify reasons in the comment area.

Summary Consideration:

A majority of commenters concurred with the need for entities to confirm agreement of Protection System coordination prior to implementing changes. Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal company practices.

Several commenters expressed concern that Requirement 4 seemed to mandate agreement without provision for the entity receiving study results to express disagreement and suggest modifications or compromise. Also some commenters disagreed with the time frames associated with Requirement 4, suggesting lengthening them and/or including a provision for an otherwise agreed-upon schedule. Others suggested the "prior to implementation" was appropriate without specifying any particular time period. Based on comments, the drafting team revised Requirement R4, Parts 4.1 and 4.2, and removed Part 4.3. The responses are as follows: Based on comments, the drafting team revised Requirement R4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."

Some commenters suggested the requirement refer to entities confirming "acceptance" rather than confirming "agreement". Others suggested the requirement refer to agreeing that coordination is achieved or maintained prior to implementing changes, rather than requiring agreement with the changes themselves. Based on these comments, the drafting team revised Requirements R4, Parts 4.1 and 4.2 as noted above.

Organization	Yes or No	Question 6 Comment
Southwest Power Pool NERC Reliability Standards	No	1. We agree with the need but feel it needs to be more detailed to include wording that would address that the coordinated owner has all appropriate data to

Organization	Yes or No	Question 6 Comment
Development Team		perform the study before his 30 day timeline begins. 2. We would also like to see a conflict resolution process included under this requirement.
Response: Thank you for your comment. **1. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.** **2. The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Pepco Holdings Inc. & Affiliates	No	1) Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D

Organization	Yes or No	Question 6 Comment
		subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? 2) Requirement R4.3 requires confirmation of agreement within 30 days of being notified of corrections made due to as found setting errors or emergency replacements of Protection System components. Again, what if the changes are not acceptable to the other party? Which entity is found not compliant, the one who proactively made the changes or the one who won't confirm agreement? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. 3) It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing some outlet for a dispute resolution process seems unfair to either party. As such, we suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined above.

Response: Thank you for your comments.

1. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**
2. **The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting**

Organization	Yes or No	Question 6 Comment
team cannot make judgments on compliance. 3. The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team believes Requirement R4 is an integral part of the standard and must remain.		
Luminant	No	Luminant agrees with the need to reach an agreement on relay coordination based on the specific circumstances in R3.3.1 and R3.3.2. However, the time period to reach agreement of 30 days should be replaced with an agreed upon time schedule by all parties.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Bonneville Power Administration	No	In many cases, one party of the interconnection is simply implementing the protection system changes provided by the other entity. Requiring the agreement of this party implies that the entity understands what is going on and is not a practical use of time and resources.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Detroit Edison	No	Recommend that if protection system changes due to emergencies need not be agreed upon before installation, then this should be stated more directly in the standard.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that “confirm” be replaced with “reach.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: “Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required.”</td></tr>
<tr><td>MRO NSRF</td><td>No</td><td>1) The NSRF agrees in general but questions how to handle situation where neighboring utility are unable or unwilling to meet required timetable? Recommend the SDT explain the process for conflict resolution.
2) Requirement 4.2 seems to mandate agreement with proposed changes which seems to go beyond the scope of the standard which is stated as “to coordinate Protection Systems”. It is suggested that this requirement be rewritten to require agreement that proper coordination will be maintained when the changes are implemented.
3) In a similar way requirement 4.3 should be rewritten.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that any conflict resolution should be handled through normal company practices.
2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.</td></tr>
<tr><td>PPL Corporation NERC</td><td>No</td><td>See comment in question #1 above.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
Registered Affiliates		
Response: Thank you for your comment. **Please see the drafting team response to your comment in Question 1.**		
Colorado Springs Utilities	No	This requirement seems to create a paper work burden that will add cost and lengthen the process of any and all transmission changes, unless there is some size significance added to the requirement under which a reduced process is involved. The maximum amount of paper work to complete must be assumed, unless there are specific limits set to restrict an overreach in how the regulation is applied.
Response: Thank you for your comment. **The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.**		
Associated Electric Cooperative, Inc., JRO00088	No	PRC-027-1 R4.2 change: Replace: “that Protection Systems(s) changes” With: “each related Protection Systems(s) change “Rationale: AECI sympathizes with the need for agreement, and believes that to be the necessary goal. However, this requirement indicates all-or-none for notified Protection System Change(s). Entities may agree on most all communicated changes, and yet a more complicated change, particularly outside of Zone 1, may require some interim compromise, or that one particular (backward-looking) be excluded until agreement is reached. Full agreement, prior to placing facilities into service, might otherwise become a method for forcing a poor compromise on protective settings.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s)**		

Organization	Yes or No	Question 6 Comment
associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Southern Company	No	If there is a requirement to agree, what happens if there is no agreement. There must be a resolution process.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Independent Electricity System Operator	No	We agree with the need to provide an agreement to the study results and to confirm acceptability of the proposed changes (other than those conditions identified in Requirement 3, Part 3.3), but R4 is unclear in a number of aspects, as follows: 1. 4.1 There is no requirement or provision for the receiving entities to express disagreement, with rationale, and R4 does not require resolving the differences. Both need to be added. 2. 4.2 Based on the language in Part 4.1, we assume R4 applies to the receiving entities. Hence we interpret 4.2 to require the receiving entities to confirm with the sending (or the initiating) entities of their agreement with the proposed changes. In that vein, the wording in 4.1 "confirm the affected Interconnected Facility owners" is unclear as to who needs to confirm with whom. Suggest to reword 4.1 to:"Prior to the in-service date of any planned change at the Interconnected Facility, confirm with the Interconnected Facility owners that initiated the changes that agreement with the Protection System(s) changes as described in Requirement R3, Part 3.1. was reached." 3. 4.3 requires that the receiving entities confirm with the initiating entities of the changes made under Part 3.3, for which prior agreements are not necessary or perhaps possible. However, there is no requirement or provision for the receiving entities to express a disagreement, with rationale, and suggest alternative setting

Organization	Yes or No	Question 6 Comment
		changes, or resolve the differences. This needs to be provided.
Response: Thank you for your comment. 1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** 2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."** 3. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
American Electric Power	No	The 90 Day window will not be sufficient during the initial R1 time frame. AEP suggests 180 days during the R1 compliance window.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
City of Austin dba Austin Energy	No	Austin Energy (AE) agrees with the need to coordinate Protection System changes; however, AE believes R4.2 is not sufficiently clear. As written, one could interpret it to mean that a Facility owner must obtain consent on the changes listed under R3.1, not just the Protection System changes (such as relay settings). AE does not believe it appropriate to require a Facility owner to gain consent on the actual change to the Facility itself (such as changes to line lengths/conductor size or replacement of transmission system Element(s), generator units or generator step-up transformer).The Guidelines and Technical Basis (p 20 of PRC-027-1 Draft #1) states, "The purpose of this requirement is to assure the effects

Organization	Yes or No	Question 6 Comment
		that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities." AE agrees with this concept and believes the SDT sufficiently covers it through R1.1.3 and R4.1. AE recommends striking R4.2 from the Standard.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s)associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
LCRA Transmission Services Corporation	No	Each Transmission Owner, Generator Owner, and Distribution Provider shall: 4.1. Within 90 calendar days after receipt, confirm acceptance with the summary results of a Protection System Coordination Study, as described in Requirement R1, Part 1.2. 4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners accept the Protection System(s) changes, as described in Requirement R3, Part 3.1
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Tri-State G & T	No	We believe that there are many instances of changes that can made to Protection Systems as required in Requirement 3, Part 3.1 that don't require coordination between entities but that might be interpreted that the change "modifies the

Organization	Yes or No	Question 6 Comment
		conditions used in the coordination of Protection Systems." Examples are load encroachment settings, communication port settings, etc. We think language needs to be added with regard to "... modifications that impact the coordination of Protection Systems between entities, of: ..." in the first bullet, if confirmation from the other entity is required.
Response: Thank you for your comment. **The drafting team believes that any change(s) noted in Requirement R3, Part 3.1 at the Interconnected Element needs to be communicated with the other entity.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	No	In general, Ingleside Cogeneration LP believes that a material unplanned change must be communicated to neighboring Facility Owners. However, this should not include an emergency replacement in kind due to a failure. This is a repair only which does not change the characteristics of the relay or the associated BES components - and therefore has no impact on interconnected owners.
Response: Thank you for your comment. **The drafting team believes this information must be communicated.**		
Wisconsin Electric Power Company	No	The requirement to reach agreement on Protection System changes prior to the project in-service date is not realistic and should be removed. While the entity that is initiating a project has a responsibility under R3 to notify other entities in order to perform a study, there is no required timeframe for these notifications to occur. Unless the initiating entity has a requirement to provide data under R3 in a timeframe sufficiently ahead of the in-service date, this is a requirement that may be impossible to achieve.
Response: Thank you for your comment. **The drafting team believes that proposed modifications to Interconnected Elements, as described in Requirement R3, Part 3.1,**		

Organization	Yes or No	Question 6 Comment
must be communicated and agreed to prior to the in-service date. This would include communication of project schedules developed relative to a project's scope. However, the drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated for a particular project. Further, the drafting team believes the entity initiating the project has incentive to consider provision of, and response to Protection System coordination issues be considered within the project schedule. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of the Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Dairyland Power Cooperative	No	How is it to be handled if two entities do not agree to the same approach?
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
Portland General Electric Company	No	No, see question 9 response
NPPD	No	Recommend the drafting team should consider several scenarios to help determine issues that will arise with putting into practice this standard with the time lines included. Some scenarios I can think of are: 1. who is liable or fineable if a required approval reply for a protection study is not made in a timely manner to a Transmission owner. It is imperative not to hold a utility responsible for another entities lack of timely responses. These issues will create murky situations when the Transmission owner does not have control over external entities ability to respond to notifications of changes within specified times. 2. If a Distribution Provider is not registered is the Transmission owner responsible for getting a reply or approval of a protection study?
Response: Thank you for your comments.		

Organization	Yes or No	Question 6 Comment
1. **The drafting team cannot make compliance judgments. Additionally, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** 2. **The standard is only applicable to the registered entities listed in the Applicability section of the standard.**		
Utility Services	No	See comment to Question 5.
mason	No	Each entity has its own philosophy and standards for Protection System design. In providing agreement to a third party design, a question of liability is also opened up. R4 should be changed from requiring agreement to requiring notification. There is enough incentive for entities to resolve material disagreements on Protection System design without the need for regulatory intervention. Regulatory involvement should only take place when business conditions call for it. Otherwise the result is higher production costs with no reliability benefit.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Trans Bay Cable	No	Comments: R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that "confirm" be replaced with "reach."
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Clark Public Utilities	No	1. The proposed Requirement R4 is not an acceptable method of confirming

Organization	Yes or No	Question 6 Comment
		agreement among parties. Requirement 4.1 requires an entity to agree with the proposed changes within 90 calendar days. What if the entity thinks the proposed changes are wrong? Other standards that require entity A to provide information to entity B provide that entity B will provide written comments to entity A within a specified period of time. 4.1 should state the following: "Within 90 calendar days after receipt, provide written comments (if any) regarding the summary results of a Protection System Study, as described in Requirement R1, Part 1.2." 2. Requirement 4.2 will require an entity needing to implement a planned change to delay the in-service date until affected entities agree with the proposal. This sets up a potential stand-off with no method of resolution. In other standards where parties provide comments the entity is required to respond to those comments within a specified period of time. However, 4.2 as worded would stop the implementation until the other parties all agree. The owner of the facility needs to have ultimate and sole control for implementing these changes and the current 4.2 would stop a project dead in its tracks until the other parties all agreed. Proceeding without this agreement would result in a standard violation and imparts power upon entities over facilities they do not own. 4.2 should state the following: "Within 30 calendar days after receipt of any written comments received per Requirement 4.1 and prior to the in-service date of any planned change at the Interconnected Facility, respond to such written comments."

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**

Organization	Yes or No	Question 6 Comment
Oncor Electric Delivery Company LLC	No	Oncor believes agreements must be reached; however, there needs to be some definitions in the Standard to define the exact meaning of the term "agreement". In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
ExxonMobil Research & Engineering	No	
Northeast Power Coordinating Council	Yes	What happens when consensus is not reached between two parties? The TO should have the responsibility for coordination.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal company practices.**		
ACES Power Marketing Standards Collaborators	Yes	Yes, we agree. The application guidelines were particularly helpful in explaining how the Requirements R3 and R4 work together.
Response: Thank you for your comment.		

Organization	Yes or No	Question 6 Comment
Operational Compliance	Yes	We suggest that R4.1, R4.3.1 and R4.3.2 all have a time period of 90 days.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Sacramento Municipal Utility District	Yes	We agree that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Xcel Energy	Yes	1. Conceivably, there could be non-reliability based reasons why an entity might not provide concurrence. An alternate avenue should be considered as allowable, such as the requesting entity working through the RC to obtain response from a non-responsive entity. 2. Similar comments on measure M9 as contained in item 3 above on measure M2. 3. Measure M9 does not account for non-acceptance under R4.3 or R4.1 as restudy or expanded studies may be required and result in a M9 violation.
Response: Thank you for your comment. **1. The drafting team believes that any conflict resolution should be handled through normal company practices.** **2. Acceptable evidence that response was provided could be registered mail confirming receipt at an address. Additional acceptable evidence would be letters, or emails acknowledging receipt.**		

Organization	Yes or No	Question 6 Comment
3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."		
Exelon	Yes	Comments: Although not stated explicitly, this question seems to be asking about R4, Part R4.2. Exelon agrees that concurrence should be reached prior to the in service date for Protection System changes that result from the equipment changes at an Interconnected Facility as described in R3, Part3.1.
Response: Thank you for your comment.		
Duke Energy	Yes	1. We support the necessity for agreement, but there can be differences in philosophies that make reaching agreement difficult. How are disagreements to be handled? 2. As the requirement is currently worded, the entity receiving the study has no alternative but to agree within the specified timeframes.
Response: Thank you for your comment. **1. The drafting team believes that any conflict resolution should be handled through normal company practices.** **2. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Dominion	Yes	
National Grid USA / Niagara Mohawk	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 6 Comment
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
Tennessee Valley Authority	Yes	
GP Strategies	Yes	
Kansas City Power & Light	Yes	
Salt River Project	Yes	
Pacific Gas and Electric Company	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 6 Comment
Liberty Electric Power LLC	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
NV Energy	Yes	
Platte River Power Authority	Yes	
MWDSC	Yes	
American Transmission Company	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
El Paso Electric Company	Yes	
South Carolina Electric and Gas	Yes	
El Paso Electric	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise		a. In R4 overall, we concur that agreement does need to be reached before changes

Organization	Yes or No	Question 6 Comment
Group		can be implemented; however, if there is a disagreement that cannot be resolved by the parties within the time frames specified, a dispute resolution process should be invoked. Otherwise, if an owner disagrees with another owner's results, it has no option but to agree or face a violation of the standard for failing to do so. b. The specific requirement in the question is in part 4.2, not R4. The list of items in R3.1 appeared reasonable. But R4.2 requires agreement to be reached "prior to the in-service date" under R4.2. Allowing agreement to be reached prior to the in-service date could allow one party to unreasonably hold up the schedule. It should be stated as follows: "Within 90 days after receiving the planned changes at the Interconnection Facility, the affected Interconnection Facility owners shall either agree with the changes, or propose alternative changes, stating why such changes are desirable. Failure to provide a response will constitute agreement with the planned changes by the non-responding Interconnecting Facility owner."
Response: Thank you for your comment. **a. The drafting team believes that any conflict resolution should be handled through normal company practices.** **b. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
Public Utility District No. 1 of Snohomish County		Comments: SNPD agrees that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		

7. In Requirement R4, the SDT established a 90 day time frame for responding to a request for agreement with a Protection System Study. Do you agree with this time frame? If not, please provide specific suggestions with your reasoning(s) in the comment area.

Summary Consideration:

The responses were equally split between agreeing and not agreeing with the 90 day time frame. Some comments wanted a longer time frame due to resource issues while others preferred a shorter time frame to prevent potential project delays. The drafting team decided not to make any changes to the time frame and responded as such: The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Element(s) to review the summary results of a Protection System Study.

There were several comments which suggested changes to the requirements. The responses included one or more of the following:

- Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."
- Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."
- Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.

Several responses involved the need for a resolution process in cases that agreement could not be reached. The drafting team responded to these comments as follows: "The drafting team believes that any conflict resolution should be handled through normal company practices".

Organization	Yes or No	Question 7 Comment
Pepco Holdings Inc. & Affiliates	No	We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined in our response to Question 6.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.		
Luminant	No	Luminant recommends that the time frame should be "according to an agreed-upon documented schedule between Transmission Owner, Generation Owner, or Distribution Provider. Luminant would recommend the removal of the 90 day requirement. 90 days may not fit all circumstances. It should be left between the parties to determine the timeline of the project and reaching agreement. This is what should be documented to ensure coordination of activities between the affected parties.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Imperial Irrigation District (IID)	No	120 calendar days are suggested instead of 90 because verification of Protection System Study needs to be performed before an agreement can be made and it is time consuming.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Bonneville Power Administration	No	BPA believes that requiring an agreement from all parties could prevent the implementation of emergency changes.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Detroit Edison	No	It appears that the "initiator" has 90 days after completing the study to provide the information while the other entity has 90 days to review and respond to the request. Suggest that a longer response time frame be considered since the "responder" may need significant time to review changes.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
Colorado Springs Utilities	No	Due to construction schedule requirements a 30 day approach should be taken.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Tennessee Valley Authority	No	There may be instances where extenuating circumstances delay agreement beyond 90 days. For long lead time or complex protection scheme projects requiring more

Organization	Yes or No	Question 7 Comment
		interaction between protective relaying engineers, exceeding the 90 day period could be acceptable to the entities involved. Evidence of mutual agreement on an extension beyond 90 days should be acceptable.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
ACES Power Marketing Standards Collaborators	No	We assume this question refers to Part 4.1. While we do not see any issues with the 90 day requirement, Part 4.1 needs to be modified to reflect what a responsible entity must do if they do not agree. As written any other response than agreement is a violation. Thus, if a TO indicates it disagrees with the results of the Protection System Study (PSS) within 90 days, it technically is in violation of the requirement. The application guidelines explain that absent agreement the revisions should be proposed. We agree with this approach but the requirement simply does not say this. It should.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Kansas City Power & Light	No	These can be matters of extreme complexity in design, implementation and operation. Stipulating that 90 days (Requirement 4.1) and 30 days (Requirement 4.3) is sufficient time to come to an agreement is presumptuous and is not necessary. Requirements 4.1 and 4.3 should stipulate that entities in receipt of proposed

Organization	Yes or No	Question 7 Comment
		changes to relay protection system(s) or component(s) be evaluated and responded to by the entity in receipt. The response could be agreement or non-agreement with concerns or objections noted in the response.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." The drafting team also combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Southern Company	No	Within "90 calendar days after receipt, confirm agreement" vs. "90 day time frame for responding to a request". Acknowledgement of the receipt and review of a change should be the limit here - agreement with the settings should not be required.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Salt River Project	No	This is too long; 60 days should be adequate
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
Pacific Gas and Electric Company	No	12 month time frame may be required to resolve the technical issues that typically prevent agreement
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Western Area Power Administration	No	See general comments below (#9).
American Electric Power	No	AEP has suggested adjusting the time requirements, as stated in Question 3 and 7. These time requirements should be included and the VSLs should be scaled accordingly.
Response: Thank you for your comment. **The drafting team believes 90 calendar days is a reasonable time for the owners of existing Interconnected Facilities to review the summary results of a Protection System Study. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Sacramento Municipal Utility District	No	No, we do not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered

Organization	Yes or No	Question 7 Comment
		under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
City of Austin dba Austin Energy	No	Austin Energy (AE) believes that 90 days is sufficient for responding to summary results of a Protection System Study, but it is not always sufficient for completing the iterative discussions that often take place to resolve questions and potential concerns. The Guidelines and Technical Basis (p19 of PRC-027-1 Draft #1) states, "R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study ...; or absent such agreement, propose revisions to achieve acceptable results." AE asks the SDT to include this "absent such agreement" concept in R4.1 and extend the timeline to accommodate such revisions to one that is mutually agreed upon by the impacted parties.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Manitoba Hydro	No	This 90 day time frame may be too long, since an agreement is required from the

Organization	Yes or No	Question 7 Comment
		interconnecting parties before the proposed protection changes can be implemented.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Exelon	No	This question differs from what is required in the language in the draft standard. In Requirement R4.1, the 90 days allowed is for entities to "confirm agreement" with the summary. If an entity must only respond at the end of 90 days, the response could be that they disagree. In this case, discrepancies must be resolved at the cost of more time. Regardless, allowing 90 days for an entity to respond before an entity can proceed with design could cause serious delays to engineering and design processes. However, until we know what is required by a Protection System study, Exelon cannot offer a suggestion for a suitable timeframe for R4.1. SDT should specifically justify the proposed 90-day time frame. Since, a 90-day time frame may not be sufficient to compile all the required design data and results for Protection System Study (PSS) and to verify the Protection Systems are coordinated within the applicable entities.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Tri-State G & T	No	We think 60 days is more appropriate. For the receiving party, 30 days may be too short, and for the sending party 90 days may be too long.

NERC

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Liberty Electric Power LLC	No	Smaller entities do not have the staff resources to respond, and must bid, contract, and receive a report. Further, they must also go through a process to allocate the funds. 180 days at a minimum, but ideally a longer period should be in place to allow for the budget process.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Public Utility District No. 1 of Snohomish County	No	Comments: SNPD does not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity believes it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after**		

Organization	Yes or No	Question 7 Comment
receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."		
Platte River Power Authority	No	We believe the agreement must be reached prior to implementing the changes. This requirement is burdensome on the entity for record keeping and does not add reliability to the BPS.
Response: Thank you for your comment. **Based on comments, the drafting team did extensively rewrite Requirement R4 including removing Requirement R4, Part 4.3.**		
MWDSC	No	More time than 90 days may be needed to reach agreement for complex system changes or because of conflicting study priorities. Allow more flexibility for the parties to agree to a time, not to exceed, e.g. 180 days.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Portland General Electric Company	No	No, It depends upon what constitutes a Protection System Study (see question 9 response
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1,**		

Organization	Yes or No	Question 7 Comment
Part 1.2, and respond as to whether further action is required."		
American Transmission Company	No	1) ATC does not agree with the 90 day time frame. 2) ATC also has the following recommendation: Requirement 4.2 states that Interconnected Facility Owners confirm that coordination is agreed to prior to placing equipment in-service. ATC believes that R4.2 is adequate to cover coordination. Therefore, the SDT should strike R4.1 and R4.3.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **2. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**		
NPPD	No	This requirement does not allow for various scenarios or conditions in the process of doing business. For example, multiple phased work or longer lead time projects where designs may change. It would be better that there be verification that studies were performed prior to in-service dates rather than tracking detailed time lines which could likely be complex and difficult to judge for audit start and end dates.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
mason	No	Do not agree with the need for documentation of "agreement with a Protection System Study" between entities. See Question 6 response.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
El Paso Electric Company	No	1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. 2) Additionally, the proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond to study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		

Organization	Yes or No	Question 7 Comment
2. The drafting team believes that any conflict resolution should be handled through normal company practices.		
El Paso Electric	No	1) EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. 2) EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. The proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond with study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Response: Thank you for your comment. **1. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **2. The drafting team believes that any conflict resolution should be handled through normal company practices.**		
ExxonMobil Research & Engineering	No	
Utility Services	No	
National Grid USA / Niagara Mohawk	Yes	1) In the event that someone hands you a study of their entire system or of all their interconnections you should only be responsible for reviewing study results for those interconnections in which you are a participant.

Organization	Yes or No	Question 7 Comment
		2) Furthermore, what if you don't agree with the study results you've been handed? The text as written literally commands you to agree with them! The text should be reworded to require a response (not necessarily agreement) within 90 days and relative only to the portion of the study applicable to interconnections you participate in.
Response: Thank you for your comment. 1. **The drafting team believes the purpose and applicability sections of the standard support your conclusion.** 2. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Northeast Power Coordinating Council	Yes	For studies of an entire system or all of its interconnections, those persons doing the study should only be responsible for reviewing the study results for those interconnections in which they participate. The wording in the text demands that the results be agreed with. The text should be reworded to require a response (not necessarily agreement) within 90 days and only pertain to the portion of the study applicable to interconnections participated in.
Response: Thank you for your comment. **The drafting team believes the purpose and applicability sections of the standard support your conclusion. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Associated Electric Cooperative, Inc., JRO00088	Yes	These facilities take time and budget to build or implement, and so 3-months prior to field-changes seems reasonable.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
Idaho Power Company	Yes	Yes, There appears to be no mechanism in the Requirement addressing if coordination changes are not acceptable. This should be addressed as 90 days could easily be exceeded in this scenario.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
South Carolina Electric and Gas	Yes	1) R4.1 only mentions R1. 2) R4.2 should be reworded to make it clear that entities have 90 days to respond to proposed protection system changes received per R3.1. The concern is that with no specified time the responding entity can delay the initiating entity's schedule even if the protection system changes were shared well in advance of the in service date.
Response: Thank you for your comment. **1. Requirement R4, Part 4.1 is intended to only reference Requirement R1.** **2. The drafting team acknowledges your concern and believes the concern you raise would need to be handled through normal company practices.**		
Dominion	Yes	Reword R4., 4.3 to read: "Within 30 calendar days after receiving notification of:"
Response: Thank you for your comment. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		

Organization	Yes or No	Question 7 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
Hydro One	Yes	
Santee Cooper	Yes	
Western Small Entity Comment Group	Yes	
MRO NSRF	Yes	
SERC Protection and Control Subcommittee	Yes	
ISO RTO Council SRC	Yes	
GP Strategies	Yes	
Operational Compliance	Yes	
Independent Electricity System Operator	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Texas Reliability Entity	Yes	
LCRA Transmission Services	Yes	

Organization	Yes or No	Question 7 Comment
Corporation		
Xcel Energy	Yes	
Tacoma Power	Yes	
Ameren	Yes	
Ingleside Cogeneration LP, (Occidental Chemical Corporation)	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Electric Power Company	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
ATCO Electric	Yes	
Illinois Municipal Electric Agency	Yes	
Trans Bay Cable	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 7 Comment
Clark Public Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		See our response to #6 above, paragraph a.

8. The team included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments? If not, please provide specific suggestions for change.

Summary Consideration:

In general, most commenters agreed with the VRF assignments and about half of the commenters agreed with the VSLs assignments. Those commenters that disagreed with several of the assigned VSLs stated that they were too stringent, or escalated too rapidly. Several commenters wanted consistency regarding the time frames established for tardiness.

The drafting team responded that they had assigned the VRFs and written the VSLs in accordance with the guidance established by NERC and FERC, and that the VSLs were assigned based upon the significance of the individual requirement parts to the overall coordination process. The drafting team made no changes to the VRFs; however, the following changes were made to the VSLs:

- For Requirement R1, Part 1.1.2, the time period for tardiness in the 'Lower' VSL was lengthened from 10 days to 30 days.

One commenter suggested adding Long-term Planning to the Time Horizon for Requirement R3. The drafting team agreed and made the suggested change.

Organization	Yes or No	Question 8 Comment
Luminant	No	Based on the comments on Q6, the VSL would need to be modified. Q7 and 9, the VSLs would change accordingly to accommodate an agreed-upon time frame for acceptable relay coordination and a method for resolving issues surrounding obtaining an acceptable coordination where differences occur.

Response: Thank you for your comment.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA believes that in general, the VRFs and VSL's are too high.
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Santee Cooper	No	The 10 day VSLs are too restrictive in R1.1.1. VSL times should be similar for all requirements. Suggest dates should be as follows: Lower - 30 days late, Moderate - more than 30 days, less than a year, High - more than a year, but completed, Severe - more than a year or not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Detroit Edison	No	The proposed VSL for R4 appears to imply that the "receiving" entity has no other choice but to confirm agreement. If the "receiving" entity has concerns with the study or changes, both parties should be responsible for resolving the issues.
Response: Thank you for your comment. **The drafting team believes your comment pertains to Requirement R4 and not the VSL. Requirement R4 does require the receiving entity to confirm agreement within a set time frame. The VSL defines the degree of non-compliance with the requirement.**		

Organization	Yes or No	Question 8 Comment
Western Small Entity Comment Group	No	We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in “guidelines and Technical Basis” that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team’s intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
PPL Corporation NERC Registered Affiliates	No	See comment in question #1 above.
SERC Protection and Control Subcommittee	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 30 days late. o Moderate VSL should be more than 30 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs; and believes the VSL for Requirement 1, Part 1.1.1 is correctly assigned. The drafting team modified Requirement 1, Part 1.1.1 to 48 months from 36**		

Organization	Yes or No	Question 8 Comment
months. The VSLs are written specific to an individual requirement and define the degree to which compliance with the requirement was not achieved; consequently, a consistent set of VSL time frames across all requirements may not be appropriate. The drafting team strives for consistency in assignment of VSLs throughout the standard.		
Colorado Springs Utilities	No	If the requirements are not reasonable, the VRFs and VSLs are also not reasonable.
Response: Thank you for your comment.		
Tennessee Valley Authority	No	We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are unreasonable and, as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSLs to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: o Lower VSL should be 60 days late. o Moderate VSL should be more than 60 days, less than a year. o High VSL should be more than a year but done. o Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Associated Electric Cooperative, Inc., JRO00088	No	See SERC PCS Comments.
ACES Power Marketing Standards Collaborators	No	(1) The time horizon for R2 should only be Long-term Planning. The study has to be completed every 24 months and while notification in Part 2.3 has to occur within 30

Organization	Yes or No	Question 8 Comment
		days it is only after that the study to satisfy the 24 month time period is complete. (2) Requirement R3 should include Long-term Planning. Transmission system expansions would be covered under Part 3.1. (3) The VSLs for Requirement R1 are gradated based on the number of days late the requirement is met for Part 1.1 but not Part 1.2. It seems Part 1.2 should have similar gradated VSLs. (4) For Requirement R4, we suggest the VSL for Part 4.2 should clearly state that any changes made during extreme operating circumstances (i.e. extreme weather) are excluded. This is essentially a question on what is meant by "planned". Are changes made to restore service in a hurricane or tornado damaged area a few days after the devastation planned? We think they are not but see how auditors could view the changes as planned particular if any level of study was required.

Response: Thank you for your comment.

The Time Horizon is a compliance element and is used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time.

1. **The drafting team respectfully disagrees and believes the time horizons are appropriate and consistent with the criteria for establishing time horizons: Long-term Planning — a planning horizon of one year or longer... Operations Planning — operating and resource plans from day-ahead up to and including seasonal.**
2. **The drafting team agrees and will make the suggested change to Requirement R3.**
3. **Please review the VSLs. Requirement 1, Part 1.2 is already gradated.**
4. **The notification of unplanned changes (for circumstances as you describe) are covered by Requirement 3, Part 3.3. The drafting team has removed the requirement for parties to reach agreement (Requirement R4, Part 4.3).**

Organization	Yes or No	Question 8 Comment
Kansas City Power & Light	No	The 10 day increments represent a 5% error and considering this is a six month requirement. The 10 day increment represents 4 - 6 working days across 2 weekends and including a holiday. Recommend the increments be increased to allow at least 10 working days which would be at least 15 calendar day increments. VSL for R2, part 2.1 - The 10 day increments represent a 1% error and considering this is a 24 month requirement. Recommend the increments be increased to 30 days to make more sense with the 24 month period.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Pacific Gas and Electric Company	No	do not line up with probability and potential severity
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Flathead Electric Cooperative, Inc.	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
ReliabilityFirst	No	ReliabiltiyFirst beleives the VRF for Requirement R4 should be High since it requires completion of the coordination activities. Lack of coordination of Protection Systems can result in larger scale outages.
Response: Thank you for your comment. **The drafting team disagrees and believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk.**		
LCRA Transmission Services Corporation	No	Objectives of R2 and R4 are mostly associated with interchange of information and the associated Violation Risk Factor for these two requirements (R2 and R4) should be LOW.
Response: Thank you for your comment. **The drafting team respectfully disagrees and believes the VRFs for Requirements R2 and R4 align with the NERC criteria as established. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner, and reaching agreement on Protection System settings and schemes. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur.**		
Ameren	No	We recommend to the SDT that a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this

Organization	Yes or No	Question 8 Comment
		urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: (a) Lower VSL should be 30 days late. (b) Moderate VSL should be more than 30 days, less than a year. (c) High VSL should be more than a year but done. (d) Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Portland General Electric Company	No	No, Severe VSL for lateness should only apply to R4.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs and believes the assigned VSLs are appropriate.**		
American Transmission Company	No	The VSLs, in general, are much more severe than the risk to the BES and should be rewritten to more accurately reflect the risk. For example: if a BES Element is replaced "like for like" with no material impact to the associated settings and a failure to notify by more than 30 days occurs, the issue is assigned a Severe VSL yet there

Organization	Yes or No	Question 8 Comment
		was no effective change to BES reliability.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. Note, in your example, if it is an exact "like for like" replacement with no setting changes – no notification would be required as this would not be covered by the standard; however, any replacement with a different style and/or changes of settings would be applicable under this standard and require notification.**		
NPPD	No	The time lines monitored down to 10, 20 or 30 days appear to be impractical in terms of monitoring for facility owners and in terms of auditing by compliance entities. This diverts the focus or sharing the data in a timely manner prior to project in service dates.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Trans Bay Cable	No	Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Response: Thank you for your comment.		

Organization	Yes or No	Question 8 Comment
The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.		
Duke Energy	No	The requirements in this standard do not have solely one activity. Also, requirements R1, R2, and R4 do not have an activity or goal stated (other than is stated in the subparts). The requirements in this standard all have sub-requirements, multiple measures and VSLs consisting of various combinations of non-compliance with sub-requirements. We think the standard could be made clearer by separating sub-requirements out as separate requirements with their own measure and VSLs.
Response: Thank you for your comment. **The drafting team considered your suggestion and declines to make the suggested changes to the standard content.**		
Oncor Electric Delivery Company LLC	No	Until 'agreement' definitions or further clarity as to what is an "agreement", can be added the Standard, Oncor does not believe that VRFs and VSLs can be established for this standard.
Response: Thank you for your comment.		
ExxonMobil Research & Engineering	No	
Liberty Electric Power LLC	No	
Dominion	No	Dominion recommends a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not

Organization	Yes or No	Question 8 Comment
		warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 30 days late. • Moderate VSL should be more than 30 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise the VSL for Requirement R1, Part 1.1.2.**		
Independent Electricity System Operator	Yes	We generally agree with the VRFs and the VSLs for the requirements as presented, but we have concerns with some of the requirements and hence reserve our comments until we see revisions made to these requirements.
Response: Thank you for your comment and support.		
Texas Reliability Entity	Yes	In the Severe VSL for R4.3, the word "entity" was left out after "The responsible . . ."
Response: Thank you for your comment. The error was corrected.		
Georgia Transmission Corporation	Yes	Meets NERC time frame practice.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 8 Comment
Southwest Power Pool NERC Reliability Standards Development Team	Yes	
National Grid USA / Niagara Mohawk	Yes	
Hydro One	Yes	
Imperial Irrigation District (IID)	Yes	
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
ISO RTO Council SRC	Yes	
Operational Compliance	Yes	
Idaho Power Company	Yes	
City of Austin dba Austin Energy	Yes	
Manitoba Hydro	Yes	
Exelon	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 8 Comment
Tri-State G & T	Yes	
NV Energy	Yes	
Dairyland Power Cooperative	Yes	
MWDSC	Yes	
ATCO Electric	Yes	
Clark Public Utilities	Yes	
South Carolina Electric and Gas	Yes	
Pepco Holdings Inc. & Affiliates		No Comments
FirstEnergy		No answer or comment at this time.
Public Service Enterprise Group		Did not evaluate.
mason		No comment

9. **If you have any other comments that you have NOT provided in response to the above questions, please provide them here. (Please do not repeat comments that you provided elsewhere.)**

Summary Consideration:

Some commenters wanted the drafting team to further modify PRC-001-2 by adding a Measure for Requirement R1 or retire the standard. This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".

Some commenters requested the time frame in Requirement 2, Part 2.1 be increased up to 60 months to coincide with studies associated with TPL-001-2 draft 5 Requirement R2, Part 2.6.1. The drafting team responded with the following: "The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require."

Numerous commenters wanted further clarification as to the definition of a Protection System Study and also what is included in a summary result. Other commenters did not want the term Protection System Study added to the NERC Glossary of Terms. The drafting team declined to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate. The drafting team did add language to the standard to specify that the term Protection System Study will not be added to the NERC Glossary of Terms. "The following terms are defined for use only within PRC-027-1, and should remain with the standard upon approval rather than being moved to the Glossary of Terms:"

Some commenters expressed concern over the number of time frames associated with the coordination process and the burden of documentation. The drafting team believes the assigned time frames and documentation are appropriate and necessary and declined to make any changes.

Numerous commenters wanted the description associated with Figure 3 clarified. The drafting team noted that: Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements. The drafting team added a note of clarification of the phrase

“Protection Systems installed to detect faults on the BES Transmission System.” Figure 3 represents a generator connected to a Distribution Provider. The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system.

A few commenters suggested the Figures in the Application Guidelines needed clarification on what the Interconnected Facilities were in the Figures. The drafting team modified the text associated with each Figure to identify the Interconnected Elements.

Some commenters expressed concern over the need to provide evidence demonstrating that the information was received by the other entity. The drafting team modified Measures M6, M7 and M8 to indicate the evidence needed is dated documentation that the information was provided during the specified time frames.

Several commenters suggested changes to the process flow chart and the drafting team modified the flow chart to be consistent with the requirements.

A few commenters wanted time frames to be established for Requirement R1, Part 1.1.3. The drafting team reiterated that there in not a single time frame that would be appropriate for every project and chose not to modify the standard.

Several commenters wanted Requirement R4 to be revised because of compliance and agreement concerns. The drafting team revised the requirement for clarity.

Several commenters requested the Applicability Section 4.2 Facilities be modified to clarify the role of Distribution Providers. The drafting team responded that they believe the Distribution Providers that own Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements should be included in the Applicability of this standard because those Protection Systems must be coordinated with the Protection Systems of other Facility owners.

A commenter requested clarification of the Fault current contribution specified in Requirement R2, Part 2. The drafting team modified Requirement R2, Part 2.2 to read “for the interconnecting bus(s) under consideration.”

A commenter expressed concern that Requirement R2 mandated that an entity perform a short circuit study even if no Protection System Study existed. The drafting team modified Requirement R2, Part 2.1 to read: "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."

Several commenters suggested various changes be made to the Purpose statement of the standard. Based on these comments, the drafting team modified the Purpose to read: "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." and also modified Requirement R1, Part 1.1 to reflect the change in the Purpose. It now reads: "Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:"

Organization	Yes or No	Question 9 Comment
ACES Power Marketing Standards Collaborators		(1) Please restate section 4.2. It states that it applies to Protection Systems installed at Interconnected Facilities. "Installed at" is not really the intention. It should be Protection Systems installed to protect Interconnected Facilities. While they most likely would be at the Facility, they do not have to be. For example, a 500 kV transmission line is a Facility. Protection Systems will not be "Installed at" the line but rather at the substations. (2) If PRC-001-3 R1 is going to be retained, it needs to be further refined. a) First, it inappropriately uses the term area when referring to a GOP. While the BA and TOP do have Balancing Authority Areas and Transmission Operator Areas, no equivalent exists with the GOP. The GOP simply operates generating units not areas. b) Second, the requirement confuses the role of the GO and GOP. In the functional model, it is the GO that is responsible for installing, setting and coordinating generation protection systems not the GOP. Thus, it is not clear what role the drafting team envisions for the GOP being familiar" with the purpose and limitation of protection system schemes applied in its area". c) Third, the requirement is written too broadly for the BA. Because the requirement compels the BA to be familiar "with the purpose and limitation

Organization	Yes or No	Question 9 Comment
		of protection system schemes applied in its area" this could literally require the BA to understand many protection schemes for which it has no direct or even indirect responsibility. For instance, distance and differential protection schemes are contained within the metered boundaries of a BA Area. This requirement would compel the BA to be familiar with them even though this knowledge would have zero impact on its decision making or responsibilities. This does not align with the responsibilities assigned to the BA in the functional model. The BA being included in this requirement is likely a vestige of the version 0 standards and should be corrected. When version 0 standards were translated from the policies, BA and TOP were simply substituted for control area regardless of the role the control area was playing in the requirement. (3) The NERC function model defines one role of the Transmission Planner as "define system protection and control needs". Should the Transmission Planner have a role in this standard? For instance, should the TP actually perform the short circuit studies? (4) The application guidelines and examples are very helpful in understanding the intent of the drafting team. However, we recommend revising the example regarding Figure 3. It would appear to assume a distribution level generator is part of the BES and subject to NERC standards. While it is possible for a generator on the distribution system to be part of the BES (i.e. if it is a Blackstart Resource), inclusion of such a generator would be unusual and an exception to the normal BES 100 kV threshold. If the generator is not part of the BES, there would be no Generation Owner registered to perform the coordination. Industry is likely to be sensitive to such an example. Removing the generator will still allow the example to communicate that a breaker and associated Protection System on the high side (100 kV or higher) of a distribution or step-down transformer would still have to be coordinated.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. 1. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."** 2. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The drafting team recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".** 3. **Although the Transmission Planner may "define system protection and control needs", it will be the owner that is responsible for determining the implementation and coordination.** 4. **Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting Transmission System Elements.**		
Ameren		(1) We support and agree with the SERC Protection & Control Subcommittee comments. (2) We commend the SDT on their high quality initial draft of PRC-027-1. (3) We recommend that the SDT delete 'operating' from the Interconnected Facilities definition because their different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. (4) The SDT needs to improve the application guidance examples by stating what constitutes the Interconnection Facility. The first example clearly enumerates the short circuit locations and values to be compared between the most recent Protection Study and the R2 2.1 value. (5) Application Guidelines Example / Figure 3: The Note should be clarified, or the example should be removed. In terms of regulatory requirements, Breaker-A and B should coordinate with Breaker-C. However, Breaker-C and the Generator relaying does not need to coordinate with Breakers at Station-1 or Station-2 unless the

Organization	Yes or No	Question 9 Comment
		generator meets the requirements of a BES element (75MW or greater). For small generators, protection on the generator to detect faults on the transmission system is for generation protection, not BES protection; as the fault currents would be too small to cause damage to the Transmission System. Generator protection is already covered in Example / Figure #2. (6) Please restate Effective Date more clearly, we suggest "PRC-027-1 shall become effective on the first day of the first calendar quarter [delete-that is] three months following [delete-beyond the date that this standard is approved by] applicable regulatory approvals [delete-authorities],..." to be consistent with the wording of other standards (e.g. PRC-005-2.) (7) Since short circuit data base models are required to perform the Protection System Study, NERC regions should have a consistent schedule for revising models. Please encourage regions to synchronize their regional modeling calendars to enable entities to have consistent models, especially near region borders, for efficient execution of PRC-027-1 (8) we recommend that the SDT add proposed NERC Standard TPL-001-2 to your list on page 5 regarding the Other Aspects of coordination. It requires short circuit studies in R2.8 for the purpose of determining if the short circuit interrupting requirements are within the interrupting capabilities of circuit breakers. (9) We strongly recommend that the SDT use the term 'change' rather than 'deviation' throughout for consistency and because the latter term is defined as being different from the norm. The new fault current value is now the norm, not abnormal or statistically different. R1 - 1.1.2 and 1.1.3 use 'change', but 'deviation' is then used about a dozen times thereafter in the document. (10) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process.

Organization	Yes or No	Question 9 Comment
		(a) The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3.(b) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. (b) Omitting ‘project schedule’ from R3 would streamline data exchange. (c) R3-3.1 and 3.3.1 should only be required IF the changes effect the tripping or coordinated functions. Digital relays include numerous settings besides these functions; and these other settings should not trigger a data exchange or study. (d) Streamline the process by measuring dates an entity sends information and receives final agreement. It is burdensome for the sending entity to also track and retain evidence showing another entity received information. Specifically change M2, M5, M6, M7, and M8 to measure the date sent. The other entity’s agreement in M9 shows that the overall process met overall time requirements and that the entities coordinated. If an entity demonstrates such a study is not required in R1, M1 should require the other entity to agree. (e) The application guidelines are generally clear and certainly clarify responsibility. We recommend somehow including their methodology in the requirements because it streamlines the exchanged data and clarifies the process in this complex and potentially voluminous undertaking.

Response: Thank you for your comment.

1. **See the response to the SERC Protection & Control Subcommittee comments.**
2. **Thank you for your support.**
3. **Based on comments, the drafting team modified Interconnected Facilities to Interconnected Elements defined as follows,**

Organization	Yes or No	Question 9 Comment

Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.

4. The drafting team has modified the figures to clarify what is the Interconnected Element.
5. Figure 3 is independent of whether the facilities are part of the BES. The intent is to identify that the coordination is required where Protection Systems are installed for the purpose of protecting transmission system elements. The drafting team has modified Figure #3.
6. The language for the Effective Date is the authorized text approved by NERC legal staff.
7. This is outside the scope of the drafting team.
8. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination.
9. The drafting team believes that the term “deviation” is properly used in R2 Part 2.2 and is synonymous with the term “change”.
10. (a) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.

    (b) The drafting team believes that omitting the “project schedule” from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.

    (c) Requirement R3, Part 3.1 states that the information shall be provided “when the proposed change modifies the conditions used in the coordination of Protection Systems…” The drafting team modified Requirement R3, Part 3.3 to eliminate Parts 3.3.1 and 3.3.2, but believes any information previously provided to another entity to ensure Protection System coordination must be provided if any of the information is changed pursuant to Part 3.3.

    (d) The drafting team believes that confirmation of receipt is an important aspect of information exchange and declines to

Organization	Yes or No	Question 9 Comment
make the suggested change. **(e) The drafting team believes that the "Guidelines and Technical Basis" is the appropriate place to elaborate on the responsibilities under the standard rather than including the information in the Requirements.**		
TransAlta Centralia Generation LLC		1) Applicability 4.2 Facilities should be Protection System installed at Interconnected Facilities that required coordination. 2) R2- For the Inteconnected Faculties only for the purpose of the generator interconnection, only the Transmission Owner providing the generator interconnection should be required to perform the tasks as mentioned in R2, not the other entity (generator) even though it is registered as the Transmission Owner. 3) R2 2.1 performs a short circuit study to determine the present fault current values, not less than once every 24 months. 24 months is too often. Suggest to change to "once every 60 months unless there is major equipment change on the system".
Response: Thank you for your comment. **1. Based on comments, the drafting team has changed the Application, 4.2 Facilities to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements."** **2. The drafting team added the following to the Rationale for R2, "(This requirement does not apply to the subject Generator Owner if it is also registered as a Transmission Owner, unless also registered as a Transmission Owner interconnecting to its own generator)" to address your comment.** **3. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2.**		
Xcel Energy		1) It appears that clarification is needed in the Application guidelines with respect to the Generator Owners, Distribution Providers and Transmission Owners. If they are the same corporate entity, do the examples indicate as such and would coordination be required as specified? (It is presumed YES but not clear...e.g. GO

Organization	Yes or No	Question 9 Comment
		"R" and TO "S" could be the same corporate entity). Figure 5 implies the letters "R", "S", and "T" refers to different corporate entities since there is a Transmission Owner R and a Transmission Owner S along with a Generator Owner T. If these letters do not indicate different corporate entities, then is it the intention of the SDT that all GO and DP facilities that connect directly to the BES be treated as "Interconnected Facilities"?. 2) Additional clarification in the Application Guide (figure 3) is required as it would imply that proof is require that generation on a tapped substation does not pose a risk to the transmission system. 3) The dates and documentation requirements for this standard will require an equivalently complex system or database for tracking in order to prove compliance. From review of the standard it appears that tracking of ~8 dates and associated supporting documents will be required for each interconnection study. Additional implementation time should be included in the standard for proper processes and tools to be in place prior to perform study or re-study work. 4) Most study work would be initiated by R3.2 and typically involve multiple data requests for varying items and with associated responses providing the information. If each email request needs a corresponding response, then much time will be required to match emails topic for topic to meet this measure. The result will be multiple of same measure for study work, increasing tracking time for engineering. (i.e. more tracking time and less engineering time per engineering FTE). If the measure is to be based on first request to last response then this would easier to implement. 5) As existing studies will fall under the measures of this document, with no grandfathering, it is likely existing studies will need to be re-evaluated. As a result, consulting services for competent protection engineering services may become limited and may impact the ability in meeting the 36 month requirement. 6) Larger regional studies with interconnection impacts may be the outcome of

Organization	Yes or No	Question 9 Comment
		more localized studies. Such studies could be recommended as a result of R2 of this document or future year models under R3.1. The time-frames specified in this standard may not be sufficient and no exception method is provided for expanded study work. (i.e.-studies beyond what is would be considered typical for an interconnection study).
Response: Thank you for your comment. 1. **The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity." The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.** 2. **Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis".** 3. **The drafting team believes that the proposed requirement time frames and effective date allow sufficient time to comply with the standard.** 4. **The drafting team did not change the standard based on this comment.** 5. **The drafting team recognizes that 36 months does not provide entities with large numbers of Interconnected Stations enough time to complete the Protection System Studies, and agrees with those commenters that pointed out that there is no evidence there is widespread miscoordination between Interconnected Stations. R 1.1.1 has been changed to: "Within 48 calendar months after the effective date of this standard, if no Protection System Study for that Interconnected Element exists"** 6. **Based on comments, the drafting team has modified requirement 4, Part 4.2 to state, "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element agree with any resulting Protection System(s) changes." The drafting team believes that regional studies as a result of Requirement 2 are outside the scope of this standard.**		
Pepco Holdings Inc. & Affiliates		1) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14,

Organization	Yes or No	Question 9 Comment
		2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of "the appropriate use of time delays in relays" in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue.

Organization	Yes or No	Question 9 Comment
		As such, although we support the overall desire to ensure that protective systems are “properly coordinated”; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. 2) PRC-001 With the vast majority of the requirements from PRC-001-1 being removed, the Title and Purpose of proposed standard PRC-001-3 no longer seem appropriate for the content remaining therein and should be revised. The only remaining requirement in PRC-001-3 states that “Each Transmission Owner, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. This does not seem to be a Protection System Coordination issue. 3) The definition of Interconnected Facilities should reference Registered Entities rather than functional, operating, or corporate entities. BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities Registered Entities (TOs, GOs, and/or DPs). 4) Is Facility and/or Element the best term(s) to use in the definition? It seems to say Elements that are joined by Elements? If not, should the definition be further revised. NERC Glossary of terms for Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. NERC Glossary of terms for Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.) 5) Does joint own lines and stations create issues? Should the definition or standard

Organization	Yes or No	Question 9 Comment
		make a distinction between principal owner and financial owners?
Response: Thank you for your comment. **1. PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing this standard based on the Standards Committee approved SAR, and is addressing directives issued by FERC in Order 693.** **2. This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **3. The drafting team has removed the term "Interconnected Facilities" and replaced it with "Interconnected Elements," which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity."** **4. The drafting team replaced the term "Interconnected Facilities" with "Interconnected Element."** **5. The drafting team believes that the individual owners' Protection Systems are well defined, but if there is joint ownership in the Protection Systems, compliance responsibility has been delegated for other standards and this standard has a similar need for delegation of responsibility.**		
Northeast Power Coordinating Council		1. Referring to the Example Process on page 22, it should not be the responsibility of Entity B to propose revisions. It should be the responsibility of the Entity in the better position to propose a revision to propose the revision. There needs to be flexibility as to who is obliged to come up with a revision. 2. Regarding Fig. 2 and Fig. 5 in the Application Guidelines, it is important that the expertise of each entity involved in an interconnection be used to ensure that there are no coordination issues. For example, Generator Owners and Transmission Owners. 3. Application Guidelines Fig. 3 requires the TO to verify that the DP's and the GO's protection systems coordinate with the TO's, even though the GO doesn't connect directly to the TO. It should be the DP that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer, and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no

Organization	Yes or No	Question 9 Comment
		transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. It would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination. The scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't own, maintain or set.
Response: Thank you for your comment. 1. **The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.** 2. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.** 3. **Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.**		
Independent Electricity System Operator		1. As a general comment, we do not support defining new terms which have limited applications (e.g. for use in one or very few standard) and which are short and therefore can be equally effectively expressed in the requirement that the term or its intended meaning is used. Adding new terms to the NERC Glossary when not absolutely necessary creates unnecessary maintenance workload and dependency among standards that use the same term, making it far more difficult to revise a standard without addressing the ripple effects. While we do not oppose to defining the term Interconnected Facilities as it serves to clarify and provide the boundary of the Facility, and we see its potential application to other standards, we disagree with defining the term "Protection System Study". The definition contains an objective "operate in the

Organization	Yes or No	Question 9 Comment
		desired sequence for clearing Faults" that should be stipulated in the standard requirements themselves. Further, as suggested below, the requirements that this term is used can be easily revised to convey the meaning of the definition: R1, 1.1 Perform a study for each Interconnected Facility to verify that Protection Systems operate in the desired sequence for clearing Faults and remove from service only those Elements required to isolate Faults as follows:1.1.1 Within 36 calendar months after the effective date of this standard, if no such study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007R1, 1.2 Provide to each affected Interconnected Facility owner a summary of the results of each study performed pursuant to Part 1.1 of this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each study.R2, 2.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent study performed under Part 1.1 of R1 and the Fault current values....Vpss = Fault current value used in the most recent studyR4, 4.1 Within 90 calendar days after receipt, confirm agreement with the summary results of a study as described in Requirement R1, Part 1.2.Conforming changes can be made to the associated Measures and VSLs. 2. We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the

Organization	Yes or No	Question 9 Comment
		"Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. 3. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after "where such explicit approval is required" in the Effective Dates Section on P. 2, to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Response: Thank you for your comment.

1. **The drafting team believes that defining the term "Protection System Study" is the most efficient way to refer to the necessary reviews and the best way to allow for description of the studies.**
2. **This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff.**
3. **The drafting team believes that the "Effective Dates" language used in the standard and in the Implementation Plan is appropriate and consistent with other reliability standards.**

Organization	Yes or No	Question 9 Comment
Southern Company		1. The separation of PRC-001-1 in three directions is appreciated. This move was a move in the right direction in our opinion. 2. Whereas the SPCTF may believe that the existing PRC-001-1 was too vague and was not measureable, we believe that the initial draft of PRC-027-1 is overly specificative. Contained within the four listed requirements are actually 11 requirements with 11 different time critical counters that are not to be violated. It is our opinion that equally effective reliability improvement results can be achieved with a standard that is of the form of something in between these two extremes. We propose to eliminate the multiple calendar based time framed requirements and simplify the eleven requirements into four simply stated requirements. The four requirements, simply, could be: 1) For each Interconnect Facility (IF), perform a Protection System coordination study/review every X years or sooner if triggered by Y. (Y = available fault current change % [r-iii below], system configuration change or other protection system change [r-ii below]); 2) IF owners must notify other IF owners of changes that may affect the other IF owner's Protection System coordination study. (list items likely to affect coordination-this list includes everything in the draft standard R3); 3) TOs are to notify other IF owners if available fault current changes significantly %; 4) IF owners must share & acknowledge receipt and review of their IF Protection System coordination study with other IF owners of that IF. 3. On figure 5 (p. 27 of the draft standard), it seems unreasonable to require that the GO coordinate their protection with that associated for breakers E, F, and G, which are three breakers away from the generator.

Organization	Yes or No	Question 9 Comment
		4. There is an error on p 5 of the Technical Justification document under Requirement R3. In the first sentence, it is R1, not R3, that requires the IF owners to evaluate the impact to their Protection Systems due to proposed changes by others.
Response: Thank you for your comment. 1. **The drafting team thanks you for your support.** 2. **The drafting team understands your concerns but believes that the requirements and associated time frames are the best way to ensure that Protection System coordination is achieved in a non-discriminatory fashion.** 3. **The drafting team believes that the Generator Owner may have overreaching elements that require coordination with breakers E, F, and G and thus made no changes to the standard based on this comment.** 4. **Based on your comment the drafting team modified the sentence to "This requires the registered functional entity initiating any change to provide the details to the other affected entities of the Interconnected Element so that the owners can evaluate the impact to their Protection Systems due to proposed changes."**		
Hydro One		1. This standard has been written on the basis that one of the Entities initiates the process and that both, assuming 2 only, conduct their own independent Protection System Studies; and then at the end of the process they agree, etc. Based on our experience, it is more efficient that both parties work in cooperation to conduct the Protection System Study and that they produce one report document which is then approved by both entities as meeting adequate coordination requirements. The Protection System Studies report shall be dated, and include the fault values at the time of assessment and should be filed as compliance evidence. 2. The SDT states "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities...." This is contrary to the NERC TRD that indicated that there were plenty of co-ordination issues during the 2003 Blackout. Suggest removing this statement as it is contradictory and serves no purpose since the documented Protection System study has to take place regardless. 3. We feel the standard would be more useful to the industry if a list of applicable

Organization	Yes or No	Question 9 Comment
		Protection System elements that require co-ordination is presented in the requirements section in line with the NERC white paper. Much like PRC-023 that identifies specific elements and corresponding numbers, we feel this approach would result in proper Protection System studies being undertaken for elements that are affected by this standard. The SDT claims some elements will be covered in other standards so the scope of elements that need co-ordination needs some clarity. 4. PRC-001-3 lists "first day of the first calendar quarter twelve months following" as the Effective Date. However, the implementation plan states that the effective date is the same as for PRC-027-1 which is "first day of the first calendar quarter that is three months beyond". Please clarify and ensure consistency. 5. Hydro One is questioning the purpose and existence of PRC-001-3 in its current form. It contains only one requirement that is very vague and not measurable. Suggest that the SDT retires that standard as a part of this project 6. To avoid confusion we ask the SDT to establish 1 to 1 correspondence between the requirements and measure. For example R2 measures should be M2 or M2.1, M2.2 rather than M3 and M4.

Response: Thank you for your comment.

1. **The drafting believes that the standard does not preclude collaboration between the affected entities when performing the Protection System Study.**
2. **The drafting team believes that the coordination issues addressed in the 2003 Blackout report were related to UFLS, UVLS, and generator controls. While there were statements of general philosophy about the need for coordination of transmission line protection, there were no examples of miscoordination. As such, the drafting team has declined to remove the suggested statement from the standard.**
3. **Based on comments, the drafting team modified the Facility Applicability 4.2 to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements," which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.**
4. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now**

Organization	Yes or No	Question 9 Comment
described as "This standard becomes effective coincidently with PRC-027-1." **5. The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.** **6. The drafting team followed the format outlined in the NERC "Standard Processes Manual," effective January 31, 2012.**		
National Grid USA / Niagara Mohawk		1. Regarding the definition of "Interconnected Facilities," when the functional and operating entities are part of the same corporate entity documented correspondence within that same corporate entity seems of little benefit. In fact, it could be the same individual wearing two hats in the same corporate entity who would have to document communications with him/herself. 2. Example process on page 22 should not automatically make it the responsibility of entity B to propose a solution to a problem discovered by entity A quite possibly resulting from system modifications initiated by entity A. Whether entity A or entity B is in a better position to propose a solution depends entirely on the circumstance and there needs to be flexibility as to who is obliged to come up with a fix. 3. Application Guidelines, Fig. 2 and Fig. 5 require the TO to verify "...the generator Protection Systems..." coordinate with the TO's systems. The scope of generator protection systems should be narrowed to just distance relays and overcurrent relays that look out onto the TO's system. If the high side winding of the transformer that interconnects to the TO is ungrounded and zero sequence overvoltage protection is provided for the transmission, then that would be appropriate to include in the scope of TO responsibilities too. The expertise in other types of generator protection likely resides with the GO and not the TO so it would be best if the GO handled the coordination of those other types of protection. 4. Application Guidelines, Fig. 3 requires the TO to verify the DP's and the GO's protection systems coordinate with the TO's. Yet the GO doesn't even connect directly to the TO. It should be the DO that checks coordination of the GO with

Organization	Yes or No	Question 9 Comment
		the DP for faults on the transmission side of the DP's substation transformer (assuming the DP has installed transmission protection at the sub) and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. Furthermore it would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination of what could be a multitude of interconnections to the DP. Furthermore, the scope of the text "....generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't even own, maintain or set. When study work is required to interconnect a GO to an entity, the entity is commonly reimbursed by the GO for study work. Yet this app guide requires a TO to perform study work for the benefit of a GO which does not even directly interconnect with it so how will the TO be reimbursed for it's efforts?

Response: Thank you for your comment.

1. **The drafting team has removed the term Interconnected Facilities and replaced it with Interconnected Elements, which is defined as "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity." The drafting team believes that the definition includes a Generation Owner and Transmission Owner that are part of the same registration, but would exclude a single Transmission Owner that is responsible for all interconnected terminals.**
2. **The drafting team believes that the Example Process does allow the flexibility that you describe. The collaboration would begin at the point where Entity B responds to Entity A with its proposal.**
3. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.**

Organization	Yes or No	Question 9 Comment
4. Based on comments received, the drafting team has revised the description relating to Figure 3 in the "Guidelines and Technical Basis" to clarify that only the Distribution Provider's Protection Systems installed to protect for Faults on Transmission System Elements are a part of the Applicability of this standard.		
Tennessee Valley Authority		a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1, Part 1.1.2 reads - "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." For Requirement R1, Part 1.1.2, we recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". b) The standard uses different formats for identifying deadlines. Sometimes "days" are used and sometime "months" are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the

Organization	Yes or No	Question 9 Comment
		time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, we recommend changing to read: "Within 90 calendar days after the completion of the Protection System Study: Provide, to each affected Interconnected Facility owner, a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)." e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing R2, Part 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3, Part 3.3 because such Protection System changes are already captured by R3, Parts 3.1 and 3.2. iii) Omitting 'project schedule' from R3 would streamline data exchange. f) Delete 'operating' from the Interconnected Facilities definition because "different functional or corporate entities" sufficiently captures all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.

Response: Thank you for your comment.

a. **The drafting team believes that your proposal does not change the requirement and the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

Organization	Yes or No	Question 9 Comment
b. The drafting team chose to use "months" for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements. c. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes. e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3. iii) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.		
SERC Protection and Control Subcommittee		a)Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another

Organization	Yes or No	Question 9 Comment
		Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." For Requirement R1-1.1.2, recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". b) The standard uses different formats for identifying deadlines. Sometimes "days" are used and sometime "months" are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1, which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual requirements where time schedules are involved, the wording of the requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the requirement whereas R1-1.2 references the time schedule at t the end of the requirement. Recommend using a standard wording format and list the time horizons in the beginning of the requirement in all requirements that have time requirements involved. For Requirement R1-1.2, recommend changing to read: "Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a

Organization	Yes or No	Question 9 Comment
		minimum the Protection System(s) reviewed and any proposed revisions)." e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing the R2 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above).Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. iii) Omitting "project schedule" from R3 would streamline data exchange. f) Delete "operating" from the Interconnected Facilities definition because different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural."The comments expressed herein represent a consensus of the views of the above named members of the Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."

Response: Thank you for your comment.

a. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

b. **The drafting team chose to use "months" for any measurable period longer than 90 calendar days and believes this does not introduce any problem with meeting the requirements.**

c. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually**

Organization	Yes or No	Question 9 Comment
(Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. d. The drafting team believes that references to the time horizons are accurately and sufficiently described and declined to make the suggested changes. e. i) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require. ii) Based on comments, the drafting team combined Requirement 3, Parts 3.3.1 and 3.3.2 into Part 3.3. However, the drafting team notes that the triggers for Requirement R3, Part 3.3 are different than those for Requirement R3, Parts 3.1 or 3.2 and therefore declines to delete Requirement R3, Part 3.3. iii) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary. f. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.		
Operational Compliance		All of the questions in this survey should elicit a "yes" response to agree with the Standard. Question 2 elicited a "no" response even though we agree with the part of the standard in the question. The questions in this survey should be worded to ask if we agree with the exact wording of the standard. For example, in Question 4 the wording of the question is different than in the Standard regarding deviation.
Response: Thank you for your comment. The drafting team agrees.		

Organization	Yes or No	Question 9 Comment
City of Austin dba Austin Energy		Austin Energy (AE) agrees with PRC-027-1 in concept and is prepared to change our vote to affirmative once the SDT addresses the items in these comments. In addition to those provided as part of the specific questions, AE provides the following comments for consideration: (1) AE requests the SDT to identify a timeframe for R1.1.3. The Guidelines and Technical Basis (p17 of PRC-027-1 Draft #1) states, "The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate ..." The flowchart on page 21 shows a system change that triggers the need for a new study leading to a box that requires the study be performed within six months. Please remove the conflicting information. (2) AE supports a timeframe that requires a Protection System Study in accordance with a mutually agreed-upon schedule that includes confirmation of agreement with summary results (per R4.1) prior to the in-service date of any planned change. AE suggests the SDT identify this timeframe in R1.1.3 and delete R4.2. (3) AE requests that the SDT change the values in the % Deviation formula (R2.2) from VSCS and VPSS to ISCS and IPSS since V is typically used for voltage. AE also requests the SDT change the variable definitions from "fault current value ..." to "fault current magnitude ..." to clarify that the phase angle is not included.

Response: Thank you for your comment.

1. **The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**
2. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."**
3. **Based on comments, the drafting team has modified the equation to replace "V" with "I." The drafting team kept the phasor values of the current in the calculation but included the percent deviation to be the absolute value of the percentage change**

Organization	Yes or No	Question 9 Comment
in the current to remove the angle from the final result.		
Oncor Electric Delivery Company LLC		Based on a thorough review of the proposed Standard, Oncor has identified several questions or comments which need to be addressed in the Standard to ensure the Requirements are clear. 1. R4.1: please provide clarification of which entity would be out of compliance if the 90 day requirement is not met - initiating entity or receiving entity or both 2. M9: What does "confirmation" mean as explained in Measure M9? 3. R4: please incorporate a definition of "agreement" 4. R4.2: please incorporate some examples for "evidence of agreement"? 5. There are two types of agreement that are needed; the first being an "agreement" with the overall projected relaying scheme (i.e. agreement with preliminary conceptual design detailing proposed protection scheme changes). This is prior to any equipment being purchased. The second agreement, which could be identified as more of a concurrence, is agreement that both relay systems coordinate from a protection standpoint (i.e. concurrence with relay setting changes). The relay setting process and concurrences occur later in the project closer to the in-service dates. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There are sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.

Organization	Yes or No	Question 9 Comment
		6. R3.1: please provide further clarification of the statement "modifies the conditions used". It would seem that most system changes would modify the conditions used even though for many of those changes, coordination would not be impacted. Oncor takes the position that the phrase provides ambiguity and subjectivity that would difficult to measure or audit.

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes..**
2. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Measure M9 was revised to read: "Acceptable evidence for Requirement R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement."**
3. **Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement"**
4. **Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm that the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes."Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement."**
5. **Based on comments, Requirement 4, Part 4.3 was removed.**
6. **Based on comments, the drafting team clarified the items in Requirement 3, Part 3.1 to indicate which items the drafting team**

Organization	Yes or No	Question 9 Comment
believes modify the conditions used in the coordination of Protection Systems.		
Luminant		Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, of Distribution Provider." The corresponding measures will also need to be modified if this language is accepted.
Response: Thank you for your comment. **The drafting team believes that 90 days is adequate time to provide the owner(s) of the Protection System(s) associated with the Interconnected Element(s) with the summary of the results of a Protection System Study and declined to change the standard based on this comment.**		
Trans Bay Cable		Comments: The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Response: Thank you for your comment. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Dominion		a). Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The PRC-001 standard should be retired or mapped to another standard.

Organization	Yes or No	Question 9 Comment
		b). The proposed definition of Protection System Study is vague and introduces subjective terms such as "demonstrates" and "desired sequences". Recommend the following definition: "A study that determines the proper selection of settings for existing or proposed protective relays in order to properly isolate Elements." c). Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - **"Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required."** For Requirement R1-1.1.2 - Omit the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". - Change R1-1.1.3 wording to read "When proposing or being notified of a change that modifies the conditions used in the coordination of Protection Systems at the Interconnected Facility unless the entity can demonstrate such a study is not required." - R2-2.2, delete reference to R2. Delete "pursuant to Requirement R2, 2.1". - Change R4-4.1 to read: "Within 90 calendar days of receiving summary results of a new Protection System Study, confirm agreement with the summary results." - Change R4-4.2 to read: "Prior to the installation of a proposed change that

Organization	Yes or No	Question 9 Comment
		modifies the existing conditions used in the coordination of Protection Systems of the Interconnected Facilities, confirm the affected Interconnected Facility owner(s) agree with the Protection System(s) change." - Change R4-4.3.1 to read: "Changes made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities, confirm the Protection System(s) changes are acceptable." - Change R4-4.3.2 to read: "Emergency replacements are made due to failures of Protection System components confirm the Protection System(s) changes are acceptable." d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, Change wording to read: **"Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)."** - Change R2- 2.3 wording to read: Within 30 calendar days after identifying that the calculation performed between the previous Protection System Study and the new study indicates a change in Fault current of 10% or greater, notify each Interconnected Facility owner, at which the 10% or greater change applies.

Organization	Yes or No	Question 9 Comment
		- Chang R3-3.2 wording to read: “Within 30 calendar days of receiving a request for information in the absence of an agreed-upon schedule or according to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider.” e). Throughout this 1st draft of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”. f). Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. g). There are several requirements stipulated throughout the draft standard creating the concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. 1). The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. 2). The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. 3). Omitting ‘project schedule’ from R3 would streamline data exchange. h). There is confusion on the connections at the end of the flow chart. Please provide clarification.

Organization	Yes or No	Question 9 Comment

Response: Thank you for your comment.

a. **The retirement of PRC-001-3 is beyond the scope of this drafting team; however, your comment will be forwarded to NERC staff.**

b. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**

c. **The drafting team believes the reference to the other requirements in this standard is the best way to both maintain consistency and to describe the requirements. The team declined to make the suggested changes.**

d. **The drafting team believes that references to the time frames are sufficient and declined to make the suggested changes.**

e. **The drafting team does not agree that the references "illustrate documentation requirements that are inconsistent." Each measurement in the standard (M1 through M10) has as evidence the statement "dated documentation (hardcopy or electronic file formats)."**

f. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.**

g. **1) The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard**

Organization	Yes or No	Question 9 Comment
does not require. **2) Requirement R3, Part 3.3 was not in the version of the standard that was sent out for comment. Based on consideration of comments the subparts (R3.31 & R3.3.2) have been combined as Requirement R3 Part 3.3.** **3) The drafting team believes that omitting the "project schedule" from the list of example data submittal will not streamline the data exchange, but the schedule is very likely required to ensure that each entity can allocate resources as necessary.** **h. The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.**		
Idaho Power Company		1. During our review it appears that an Entity will need to maintain an exceedingly large list of contacts for all Interconnected Facilities in order to ensure that the appropriate personnel receive and respond appropriately to Protection System coordination requests as Required by this Standard. With the probability of regular turnover occurring (retirements, transfers, etc.) at Interconnected Facilities, it would be helpful for a master list of Interconnected Facility Contacts for Protection Systems be held by a centralized Entity, such as a Reliability Coordinator, in order for an Entity to meet the timeframes specified and facilitate reliability via compliance with this Standard. 2. This Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems. It does not however, guide an Entity to set relays that will ensure proper coordination. Having a separate Entity verify coordination is desirable, but differences in experience, expertise, and analysis tools between Entities will not ensure proper coordination if methods of checking are not also part of the Requirements.
Response: Thank you for your comment. **1. Your comments concerning the need for a current listing of "Interconnected Facility Contacts" is very perceptive, but cannot be addressed by the Requirements of the standard. The drafting team believes that ultimately it is the owner's responsibility**		

Organization	Yes or No	Question 9 Comment
to maintain this list; however, if you can reach an agreement with the Reliability Coordinator, that may be option. **2. The drafting team agrees with your comment that the "Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems" but disagrees with your assertion that "Entities will not ensure proper coordination if methods of checking are not also part of the requirements." The drafting team believes that all interconnected Protection System Owners have the capability of self checking their setting that will ensure coordination without making external checking of Protection Studies a Requirement of this standard.**		
FirstEnergy		FE offers the following additional comments: a. PRC-001-2 R1 - This requirement is vague and causes difficulties in consistent interpretations between entities and auditors. We ask the drafting team to revise the wording to clarify the expectations, such as including the types of protections system limitations they should be aware of. Enhancements to this requirement were also suggested in the "NERC SPCTF Assessment of Standard PRC-001-0 - System Protection Coordination" which is attached to the SAR of this project. In their assessment of R1 of PRC-001, the SPCTF said "This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. .. It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems." We ask the SDT to review this assessment and make changes to PRC-001 and PRC-027 to assure the reliability goal of PRC-001 R1 is met. b. With the approval of PRC-027-1, Requirements R3 and R4 will be retired from PRC-001-1 (Requirements R2 & R3 from PRC-001-2, approved as part of the Real-time Operations Project 2007-03) PRC-001-3 will have the same effective date as PRC-027-1. However, in the redlined version of PRC-001-3, the effective date is designated as "the first day of the calendar quarter twelve months following applicable regulatory approval". This is not what is specified in the

Organization	Yes or No	Question 9 Comment
		Implementation Plan.
Response: Thank you for your comment. a. **The drafting team believes that Requirement R1 falls outside the scope of Project 2007-06 and should remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard.** b. **The drafting team has modified the effective dates so they will be consistent. The effective date for PRC-001-3 is now described as "This standard becomes effective coincidently with PRC-027-1."**		
LCRA Transmission Services Corporation		General Comment: First, as industry comments are considered by the SDT, the standard must continue to take into consideration that the fundamental objective of a protection system is to prevent equipment damage that may occur as a result of a short circuit by ensuring fault isolation. The secondary objective is to maintain the power delivery capability in the rest of the system during a fault. This must not be compromised. Second, setting of protective relays is an art and finding a balance between dependability and security is already a challenge and may be an area of disagreement amongst owners (in some cases entities may end up "agreeing to disagree"). The standard should not take away the protection system owner's responsibility and right to set its own protection systems by requiring "Approval" from other interconnection entities at the Interconnected Facility. Specific Comments: Title of the proposed standard- The title for this standard is misleading since it only applies to locations that contain Interconnected Facilities. LCRA TSC suggests changing the title to "Protection System Coordination for Interconnection Facilities" Terms-Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems maintain proper selectivity while clearing Faults.
Response: Thank you for your comment.		

Organization	Yes or No	Question 9 Comment
The drafting team agrees that two objectives of a Protection System are to "prevent equipment damage due to faults" and to "maintain the power delivery capability in the rest of the system during a fault." **Based on comments concerning agreement, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."** **The drafting team does not believe the standard title is misleading and therefore did not adopt your recommended title.** **The drafting team does not agree with expanding Protection System Study to "Protection System Coordination Study. Also the drafting team does not agree that "maintain proper selectivity while clearing Faults" adds significant clarity to the current definition of a Protection System Study.**		
Western Area Power Administration		General: Western disagrees with NERC standards becoming too specific on technical issues such as protective relay coordination. Protection Engineers are highly skilled and trained in system coordination and should be left to determine the proper course of action without the hindrance of PRC-027-1 requirements. There is a reason why, historically, protection system coordination has been termed "the Art and Science of Protective Relaying." The proposed standard also mentions that "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated. Specific issues: a. We have concerns over what NERC considers to be a "Protection System Study". Needs clearer definition. - Swap requirement positions R1 and R3. I.e. make R1 be R3 and R3 be R1.

Organization	Yes or No	Question 9 Comment
		b. R2.2: Provide equation. And, use “I” instead of “V” when referring to current. c. R2.2: What values are being referred to for deviation calculation? (i.e. ground current, phase current, positive sequence, etc.) d. R2.2: Clarify the fault current contribution or provide a table specifying the details e. R3.1: Last bullet, suggest making the statement “Replacement of the transformer(s)” to cover all transformers. f. R3.2: How does the neighboring entity know when to request? g. R3: What are the details to be provided? Should only be for significant changes. h. Concerned about dates and timelines associated with this standard. Often schedules and tasks change during design, checkout and commissioning. R1.1.3 and R3 need to be clarified. i. Western believes that this standard will create more questions than it answers. The standard, as written, is not clear or concise and would surely lead to CAN's and FAQ's.

Response: Thank you for your comment

a. **The drafting team believes that the definition of Protection System Study, “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults” is understandable and succinct and does not need to be more clearly defined. Also the drafting team does not believe that Requirements R1 and R3 need to be swapped.**

b. **Per your suggestion and others, the drafting team has modified the equation to replace “V” with “I”.**

c. **The standard has been changed to refer to “Single line to ground and 3-phase for the interconnecting bus(s) under consideration” for the “deviation calculation.”**

d. **Based on comments the fault current contribution in Requirement R2, Part 2.2 has been clarified to be “for the interconnecting bus(s) under consideration.”**

Organization	Yes or No	Question 9 Comment
e. Other transformers are included in the second bullet which is now a combination of the previous version's second and third bullets. **f. In R3 Part 3.2 the "neighboring entity" can request information related to the coordination of Protection Systems of an Interconnected Element whenever it desires the information.** **g. The details to be provided for R3 Part R3.1, Part 3.2, and Part 3.3 of the standard are discussed in their respective parts and the Application Guidelines of the standard. However, the individual circumstance may dictate additional details that are required for a relay coordination study.** **h. The standard takes into account "schedules and tasks" changing "during design" by not establishing "dates and timelines" for Requirement R 3 Part 3.1. The drafting team believes that Requirement R3 and Requirement R1, Part 1.1. 3 have sufficient clarity in the respective standard Requirements and the Application Guidelines associated with the Requirements.** **i. The posting of the standard is intended to provide the opportunity for the drafting team to address industry comments and provide clarifications to the industry which will hopefully eliminate the need for CANs and FAQs.**		
Southern Minnesota Municipal Power Agency		I agree with and support the comments of the MRO's NERC Standards Review Forum (NSRF).
Response: Thank you for your comment. **Please see the response to MRO's NERC Standards Review Forum (NSRF)**		
Illinois Municipal Electric Agency		IMEA recommends language be included in 4.2 Facilities to clarify the standard does not apply to a DP protective device that only detects a fault on a transmission element and does not trip an interrupting device that interrupts current supplied directly from the BES. To minimize misinterpretation and potential impact on small entity resources, it would strengthen the standard if Section 4.2 Applicability language specifies the standard does not apply to a DP that does not own a BES Element/Facility.
Response: Thank you for your comment. **The drafting team believes Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on**		

Organization	Yes or No	Question 9 Comment
Interconnected Elements of the BES and that require coordination for isolating those faulted Elements" should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners.		
American Transmission Company		1. In general, ATC agrees with the need to modify PRC-001. However, PRC-027 as written expands the scope of PRC-001 by including Distribution Providers (DP). 2. The SDT, on both page 6 and 16 states that there is "no evidence of widespread miscoordination between Interconnected Facilities..." They further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperation." Based on the above statements, ATC questions the need for the level of prescription in the standard. 3. ATC asks the SDT to update the numbering for measures to match the requirement numbering. 4. Reliability Standard TPL-001-2, which has been approved by NERC BOT, requires short circuit analysis. ATC believes that PRC-027-R2.1 is duplicative.
Response: Thank you for your comment. **1. The drafting team believes Distribution Providers that own Protection Systems installed for the primary function of detecting Faults on BES Elements should be included in the Applicability of this standard because these Protection Systems must be coordinated with the Protection Systems of other Facility owners. To add clarity to this issue, the drafting team revised Applicability Section 4.2 Facilities as follows: Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements. Additionally, the drafting team changed the term "Interconnected Facilities" to Interconnected "Elements" defined as follows: "An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity"** **2. The drafting team stands by the quoted statement that there is "no evidence of widespread miscoordination between Interconnected Elements." However, because communication of changes at the interconnection or changes that effect the**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">Protection Systems at an Interconnected Element is required for proper coordination, the “level of prescription in the standard” is required.
3. The drafting team followed the format outlined in the NERC “Standard Processes Manual,” effective January 31, 2012.
4. The drafting team believes that the referenced requirement in TPL-001-2 is related to interrupting capabilities and is not directly related to Protection System coordination. The reliability intent and purpose of the two standards is different and therefore they are not "duplicative”.</td></tr>
<tr><td>Southwest Power Pool NERC Reliability Standards Development Team</td><td></td><td>1. In R2 the 24 month time period needs to be changed to 60 months. If fault currents are already being calculated for changes to the system there should be little to no need for a more current check of the fault currents. We feel like the 24 months could be burdensome to smaller entities.
2. We would ask that PRC-001-3 be retired and the requirement in it to be moved to a SAR for an existing PER training standard. It also seems incomplete that a standard with a single requirement has no measures.
3. Is there a need for the defined term “Protection System Study” in this standard to also be a new term in the NERC glossary of terms? Is there other wording that could be used in place of this new term since it is only being used as part of this standard?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2.
2. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, “The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard”.
3. The drafting team believes that the definition of Protection System Study is needed but based on your comment the drafting team has specified that the new term will not be added to the NERC glossary of terms.</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
Bonneville Power Administration		Interconnections are no more prone to misoperations than other power system elements. A logical conclusion is that if the requirements of this standard are put in place for interconnected facilities, they should be put in place for all power system elements. The industry is quickly approaching a prescriptive environment in the protective relaying field which attempts to replace experience and judgment with a massive set of rules. These rules will never be able to eliminate miscoordination and misoperations, and the more rules we have, the more time and resources are diverted from dealing with the critical issues that arise. Entities are no longer free to use experience and judgment to decide what work is most important and instead, focus time and energy on the relentless schedule of NERC requirements. The purpose of the original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities. This should require only a simple exchange of data between entities when new facilities are added or changes are made. BPA implores the SDT to reduce the burden of the proposed standard by simplifying it and returning to the basic original purpose.
Response: Thank you for your comment. **The drafting team agrees that "Interconnections are no more prone to misoperations than other power system elements" and that the intent of the "original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities." The Purpose of PRC-027-1 "To coordinate Protection Systems for Interconnected Elements …." does not imply that the requirements of PRC-027-1, when put in place for interconnected elements, should be put in place for all power system elements. Because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, the level of prescription in PRC-027-1 is required. The drafting team believes that the coordination of other system elements that are owned by the same Transmission Owner, Generator Owner, or Distribution Provider are governed by their internal protection coordination quality control processes.**		
Tacoma Power		1. Is it the expectation of the SDT that Protection System coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1? 2. If such issues are identified, is it the intention of the SDT that these issues

Organization	Yes or No	Question 9 Comment
		would constitute violations of PRC-027-1, provided that the process described in PRC-027-1 for remedying these issues is followed? 3. Transmission Owners depend on each other for accurate short circuit models. As proposed, PRC-027-1 does not appear to clearly address sharing of short circuit modeling information among Transmission Owners when incremental changes are made within a Transmission Owner's system. For example, incremental changes in adjacent Transmission Owners' systems may result in a 5% change in Fault current at an Interconnected Facility when the changes are considered separately, but when the changes are considered together, the Fault current might change by 10%. While the +/- 10 % change in an Interconnected Facility's Fault current value as a trigger appears to be reasonable, the proposed standard offers no guidance or requirements concerning the accuracy of an entity's short circuit model or the methods used to determine Element impedances. This issue is most pronounced for zero-sequence impedance, and to a lesser extent negative-sequence impedance, since these parameters are used infrequently in system planning studies. It seems that some standardized approach for determining impedance parameters may need to be developed, whether in this standard or in another standard, provided that some latitude is afforded entities based upon sound engineering judgment. 4. In R2.2, why is it not sufficient to simply include the following in the parentheses: "single line to ground and 3-phase for the bus(s) under consideration"?" 5. The formulas in R2 use V for current. For clarity's sake, current should be denoted using the letter I." 6. Under R3.2, if all applicable entities agree to a schedule, was it the intention of the SDT that the agreed-upon schedule could be longer than 30 calendar days? 7. M8 requires that an entity have evidence that other entities received

Organization	Yes or No	Question 9 Comment
		information pursuant to R3.3.1 and R3.3.2. What if, despite due diligence, one or more entities do not acknowledge receipt? 8. Since notification pursuant to R3.3 is after the fact, to be compliant, an entity depends upon one or more other entities to acknowledge receipt, but there does not appear to be a regulatory requirement for them to acknowledge receipt in a timely manner, only a requirement to confirm that the changes are acceptable within 30 days of receipt pursuant to R4.3. Consequently, if Entity A notifies Entity B of changes pursuant to R3.3 in 15 calendar days, Entity B would have until 45 calendar days following the change to respond. However, by this time, Entity A might not have documentation that it met its requirements under R3.3. Another challenge with R3.3 and R4.3 is that the language seems to assume that both entities will agree to the changes. While this should usually be the case, there may be instances in which the entity receiving notice may not find the changes acceptable. 9. Additionally, the language in R4.3 may influence the entity receiving the notice to deem the changes as being acceptable, even if they are not, in order to meet the 30 calendar day timeframe. 10. Tacoma Power thanks the SDT for including Figure 4 in the Application Guidelines. 11. In Figure 5 of the Application Guidelines, why would it be necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D? Is this language intended to address reverse elements that are independent of communications systems? Is it intended to include bus differential, which would be the scheme commonly applied? Or, is there some other reason? 12. To what extent can this standard be enforced within a Transmission Owner's system? For example, in Figure 1 of the Application Guidelines, in addition to verifying that there are no coordination issues between Protection System

Organization	Yes or No	Question 9 Comment
		settings associated with Breaker A and, say, Breaker F, does the SDT intend that this standard could be construed to grant regulatory authority to audit that a Protection System Study was completed to verify that there are no coordination issues between Protection System settings associated with Breaker F and other breakers within Transmission Owner S's system? 13. While Protection System settings associated with Breakers A and F may be coordinated, Breaker F may not be coordinated with other Protection System settings within Transmission Owner S's system such that Protection System settings associated with Breaker A might also not be coordinated for some Faults within Transmission Owner S's system. It is believed that this type of situation should be rare and that the scope of this proposed standard should be limited to audit and enforcement of Protection Systems at the Interconnected Facilities, as depicted in Figures 1, 2, 3, and 5. Assume that there is documentation supporting coordination of Protection Systems at Interconnected Facilities. However, during a Fault, a Mis-operation occurs, and the cause of the Mis-operation is attributed to mis-coordination, despite good faith on the part of the entities to coordinate Protection Systems. Is it the intention of the SDT that this Mis-operation would be construed as a violation of PRC-027-1? For example, although they are generally addressed to some degree in Protection System Studies, but often implicitly through margins, factors of safety, etc., phenomena such as CT saturation or DC offset are not always directly analyzed in Protection System Studies and could lead to mis-coordination even if Protection System settings appear to be coordinated in documentation. 14. It is not clear what responsibility the TO has if it models a generator's short circuit capability incorrectly. 15. The proposed changes to PRC-001 (proposed version 3) are supported. 16. As a reminder to the SDT, Protection System design and application is part science and part art, and it may be difficult to thoroughly audit and enforce

Organization	Yes or No	Question 9 Comment
		the latter. Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.

Response: Thank you for your comment.

1. **The drafting team believes that coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1 and this is the basis for this requirement.**
2. **The drafting team believes that any coordination issues identified when Protection System Studies are performed pursuant to Requirement R1, Part R1.1.1, Part 1.1.2 or Part 1.1.3 are discovered would lead to corrective actions as identifies in the other requirements.**
3. **The drafting team believes that developing a standardized approach for determining impedance parameters is outside the scope of this project.**
4. **The drafting team believes the existing wording is appropriate and did not make your suggested change.**
5. **Per your suggestion and others, the drafting team has modified the equation to replace "V" with "I"**
6. **Under Requirement R3 Part 3.2, if all applicable entities agree to a schedule, the intention of the drafting team is that the agreed-upon schedule could be longer than 30 calendar days.**
7. **Measure M8 has been modified to indicate that information was provided within 30 days; therefore, an acknowledgement of receipt is no longer required.**
8. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Also based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**
9. **Based on comments, the drafting team removed Requirement R4, Part 4.3.**
10. **Thank you for the comment.**
11. **In Figure 5 of the Application Guidelines, it is necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D if there are reverse tripping elements that are independent of communications systems.**

Organization	Yes or No	Question 9 Comment
12. The drafting team believes that the requirements of PRC-027-1 extend to only to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements for the BES and that require coordination for isolating those faulted Elements." As stated in the text for Figure 1 of the Application Guidelines, the only Interconnected Element identified is the transmission line between Breakers A and E. **13. A Misoperation is not a violation of this standard.** **14. The Transmission Owner is identified as the entity responsible for performing the Fault current studies in Requirement R2, Part 2.1. The standard does not address incorrect modeling of a generator's short circuit capability.** **15. Thank you for your support.** **16. Thank you for your reminder and your comments.**		
Detroit Edison		1. It is suggested that the standard include other relevant information that could be needed for a protection system study such as critical clearing times determined from stability studies. 2. In Figure 3, what Protection System Studies would be required if the Distribution Provider does not have a Protection System designed to protect BES transmission system elements? 3. Also, please clarify if the transformers in Figures 3 and 4 are BES elements. 4. Also, further clarification, including some examples, would be beneficial to explain what does and what does not constitute "Protection Systems installed to protect Transmission System Elements" by a Distribution Provider.
Response: Thank you for your comment. **1. The drafting team believes that the data required by a protection system study are discussed in the technical guideline is a suggested list. Other information such as critical clearing times may be required for a specific location's relay coordination study and can be requested by either entity as needed.** **2. The note in the description for Figure 3 states: "A Protection System Study is required per this standard for this example if a Protection System at the Distribution Provider's substation is designed to detect Faults on the BES Transmission System."**		

Organization	Yes or No	Question 9 Comment
Therefore, a Protection System Study would not be required. . **3. The drafting team believes the transformers in Figures 3 and 4 are not BES Elements.** **4. Based on your comment, the drafting team has added a note to the text of Figure 3.**		
Ingleside Cogeneration LP, (Occidental Chemical Corporation)		It would seem that M9 should be reworded slightly so that it is clear that the compliance burden is placed on the party sending the confirmation. It seems like it should read “demonstrating the confirmation was sent within the respective time frames” instead of “demonstrating the confirmation was achieved within the respective time frames.” In other words, Requirement 4 compliance is solely for the confirming party to show evidence, not the submitting party.
Response: Thank you for your comment. **Based on comments, the drafting team revised Measure M9 to read: “Acceptable evidence for R4, Part 4.1 is dated documentation (hardcopy or electronic file formats) demonstrating that response was provided according to the agreed-upon schedule, or within 90 calendar days absent such an agreement.”**		
Lincoln Electric System		1. LES recommends additional clarity be added to explain how an entity would coordinate the efforts of the many different protection schemes - for example, pilot tripping, primary, secondary, ground overcurrent, breaker failure, LOP supervised, etc. - to determine only Elements required to isolate Faults are removed from service. Does an entity consider only its fastest scheme, slowest scheme, or all of them? 2. Additionally, is an entity to consider contingencies such as primary or secondary relay out of service, loss of communications, etc.? What about backup tripping? Until the above is addressed, an entity will have a difficult time discerning what exactly needs to be studied. 3. Please take into consideration that system protection is a complicated subject and each entity has its own philosophies on how to do it. Entities should be allowed to use their individual engineering judgment when designing their

Organization	Yes or No	Question 9 Comment
		systems and ensuring it will work to their own standards as well as in compliance with the NERC standards. 4. LES is concerned that there may be potential for mis-coordination between PRC-027-1 and PRC-004-2a. If a misoperation is defined as tripping too much out of service during an event, does the entity become instantly non-compliant with PRC-027-1 since it should have been studied not to do so? Any correlation between these two standards should be considered and clearly defined. 5. LES recommends the 24 month timeframe specified in R2.1 be extended to 60 months. Historically, fault currents tend to increase gradually over time; therefore, an entity may never see a 10% increase between studies, but will most likely see a 10% increase over a larger timeframe at which point they would never be required to perform a study.

Response: Thank you for your comment.

1. **In your example, all relays responding to Fault conditions should be included in your Protection System Study.**
2. **All relays responding to Fault conditions installed for the Interconnected Element should be included in your Protection System Study.**
3. **The drafting team agrees with your assessment that each entity has its own philosophies on how to protect the system. The drafting team believes that PRC-027-1 does not infringe on the ability of entities to protect their elements. However, the purpose of PRC-027-1 is "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults."**
4. **A Misoperation is not a violation of this standard.**
5. **The drafting team believes as stated in the rational for Requirement R2 Part 2.1 that, "Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." Specific to your question, please note that the 10% deviation is in relation to the most recent Protection System Study.**

Organization	Yes or No	Question 9 Comment
Massachusetts Municipal Wholesale Electric Company		MMWEC endorses the comments submitted by NPCC.
Response: Thank you for your comment. **See the response to comments submitted by NPCC.**		
NPPD		1. On page 6 and 16 there are statements such as "no evidence there is widespread miscoordination between Interconnected Facilities..." and on page 16 "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." Clarify what the need is for this standard? This proposed standard significantly increases the record keeping requirements and subsequent resources needed for each Facility owner but does not appear to have a justification. 2. I find the numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking communications between entities. This draft standard includes time lines ranging from "prior to in service date, 30 days, 60 days, 90 days, 6 months, 2 years and 3 years". I suggest fewer and longer time lines with the focus on if the sharing of information took place and not on when did it take place. 3. The SDT statement below should be generalized to the standard as a whole: "The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated

Organization	Yes or No	Question 9 Comment
		project on schedule and confirm the changes are acceptable "prior to the in-service date," 4. Clarify the size of generation for Distribution Providers that would make this standard applicable for all involved entities. I would expect that the BES phase II definition or registry criteria would be referenced.
Response: Thank you for your comment. **1. The drafting team stands by the quoted statement that there is "no evidence of widespread miscoordination between Interconnected Elements." However, because communication of changes at the interconnection or changes that effect the Protection Systems at an Interconnected Element is required for proper coordination, The drafting team believes the requirements laid out in the standard are appropriate.** **2. The drafting team believes that to make PRC-027-1 measurable and enforceable, the listed times are necessary.** **3. The drafting team believes they applied reasonable and appropriate time frames for the identified activities and provided flexibility by including the option to agree upon an alternate schedule where deemed appropriate.** **4. Figure 3 is independent of the size of the generation. The intent is to identify that coordination is required where Protection Systems are installed for the purpose of detecting Faults on the Transmission System.**		
ExxonMobil Research & Engineering		PRC-001-3 has a single requirement with no associated measure. Any standard requirement whose implementation can address a reliability gap in the Bulk Electric System should possess a quality that can be measured. The SDT should modify PRC-001-3 and provide a measure for Requirement R1 or redact the standard in its entirety.

Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**		
Progress Energy		Progress Energy request re-evaluation of time for performing Short circuit study in R 2.1. Request 36 months which is same time frame in R1.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation.**		
Dairyland Power Cooperative		R2, 2.1 "Perform a short circuit study to determine the present Fault current values, not less than once every24 months." is excessive. Yes, short circuit databases are updated annually or even more frequently at times based on system changes. However, to require a full short circuit study every 24 months is too frequent. Changes on the system don't necessarily warrant a full short circuit study, but maybe a study for the affected area. This is adding an unnecessary burden to the industry.
Response: Thank you for your comment. **Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. The drafting team believes studies associated with changes that would affect the coordination in less time would be triggered by other requirements in this standard.**		
MRO NSRF		1. Recommend that the wording of R2 need be modified to allow a grace period for implementation, as was done in R1. As written, R2 requires an immediate short circuit study, even if no protection system study is required by R1.1.1. 2. The SDT, on both page 6 and 16 states that there is "no evidence there is widespread mis-coordination between Interconnected Facilities..." They

		further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." Why, then, is this standard even needed? It adds an onerous burden of record keeping on each Facility owner without justification for doing so. 3. Since these are still zero defect standards, should exceptions be included for required operational replacements due to events (e.g. such as storms or immediate equipment replacement). When the lights are out and a technician replaces a CT or VT with a slightly different ratio but compensates by altering the relay settings, there is no way to perform an instant system protection study when the equipment change out was required to support system reliability. The NSRF understands that a "planned" changed be studied before hand, but how will this be viewed when a change is needed that is "unplanned"? Please clarify
Response: Thank you for your comment. **1. Short circuit databases are customarily updated annually, so the drafting team believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation at the interconnecting buses. Based on your comment, the drafting team modified Requirement R2, Part 2.1 to read: "At least once every 24 months, perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus where a Protection System Study is available per Requirement R1."** **2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.** **3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3. Requirement R3, Part 3.3 was changed to "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."**		
Manitoba Hydro		1. Regarding R1, it is not clear what specifically the Protection System Study should include. - According the application guidelines on page 17, it states:

		"Data used to determine Fault currents in performing the study", what data does this refer to? 2. Also it states that it should include "listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study". It is not clear if it should include a list of all the enabled protection elements and their settings of the protection system package or the package only. Should it include the protection system on the interconnected facilities only or on the immediate adjacent elements as well? 3. The Application guidelines say it should list any issues associated with the relay settings. It is not clear what should be considered as issues. Does a protection mis-coordination occur only under contingencies (such as primary protection element fails) consider an issue? Do backup protection elements have to coordinate with backup protection elements? 4. Regarding R2, it is not clear what fault current value should be used for the short circuit study. Should it be the total fault current of the interconnecting bus? Or should it be the total fault current of the interconnecting bus excluding the contribution from the interconnected facilities?

Response: Thank you for your comment.

1. **The drafting team declines to modify the definition of the Protection System Study but did add the following to the description in the "Guidelines and Technical Basis": "System conditions used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions." The drafting team believes that the full description in the Guidelines and Technical Basis is now adequate and appropriate.**
2. **The entity should include all protection elements reviewed for coordination. It is up to the entity to determine what and where those elements are for the particular system configuration.**
3. **It is up to the Owner to determine what is appropriate for their system and under what contingencies the relays should coordinate. Any issued identified that fall outside of their normal practice would need to be listed.**
4. **The drafting team modified Requirement 2.1 to read "At least once every 24 months: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus**

where a Protection System Study is available per Requirement R1.”		
ReliabilityFirst		ReliabilityFirst offers the following comments for consideration: 1. Requirements R1, R2 and R4 a. Requirements R1, R2 and R4 do not follow the format of a typical Results Based Standard requirement (i.e. the parent requirement simply states "the entity shall:"). Result Based Standard risk based requirements should be in the following format: "who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." ReliabilityFirst recommends modifying these three standards to conform to the Results Based Standard format. 2. Requirement R2a. ReliabilityFirst questions why Transmission Owners only need to perform a short circuit study on Interconnected Facilities and not their internal system Facilities as well (Requirement R2). ReliabilityFirst believes it would be beneficial for Transmission owners to be required to determine present fault current values (and calculate the percent deviation between the Fault current values) for all internal system Facilities. 3. Need for PRC-001-1 Requirement R1a. ReliabilityFirst believes PRC-001-1 Requirement R1 is ambiguous and believes the intent is covered in the NERC PER-003-1 standard. It will be very hard for an applicable entity to show that they are “familiar” with the purpose and limitations of protection system schemes applied in its area. Since ReliabilityFirst believes R1 does not enhance reliability, ReliabilityFirst recommends retiring PRC-001-1 Requirement R1 consistent with the effective date of the NERC PER-003-1 standard (effective date of 10/01/2012).

Response: Thank you for your comment.

1. **The standard has been reviewed by NERC Quality Review for format and content.**
2. **The previous PRC-001 only applied to coordination between TOPs, GOPs and BAs. The drafting team has chosen not to include internal facilities for two main reasons: the extreme documentation burden that would be involved for minimal benefit as most of this work is done by the same organization, and the drafting team believes that the entities’ internal facilities are completely in their control and are the responsibility of the entity. Failure to properly design and implement internal Protection Systems would be an internal lack of procedures and/or a human performance issue which are both outside the**

scope of this standard. **3. This drafting team is not addressing the refinement of PRC-001-1 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**		
Kansas City Power & Light		1. Requirement 1.1 of R1 states, "Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:". The purpose of this standard should not be to remove from service only those Elements required to isolate Faults, therefore 1.1 above should state, "Perform a Protection System Study for each Interconnected Facility as follows:". 2. Requirement 1.1.2 of R1 states, "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." Since this Requirement is an action as a result of requirement R2 and as noted in the response to question 6 above, R2 should be deleted. 3. If the SDT is adamant about having a periodic review of fault current levels then the fault current level should be increased to 20% on the protected line. A 10% fault current change is not significant enough to require a new protection system study. 4. Requirements R4.3 and R3.3 are actions as a result of a misoperation and because there is already a standard (PRC-004) that deals with misoperations these two requirements should not be covered in this standard if changes need to be made due to misoperations they should be made in the misoperation standard (PRC-004). This standard is not intended to replace the Misoperation Standard and any requirements addressing misoperations gives FERC, NERC and the Audit Teams the wrong impression of the intent of this standard. 5. All Protection System Studies are dependent on accurate system models.

		Individual Entities should not be responsible for development and maintenance of an accurate Regional model or model to be used between Regions. Individual Entities should only be responsible for providing the information on their system to the Regional Entity so that an accurate model can be maintained by the RC. I propose that this standard be applicable to the Region and require the Region to maintain an accurate model that includes zero sequence impedance and is useful for Protection System Studies. This system model also needs to be accurate between Regions for Protection System Studies that span between Regions. This will require that the standard also be applicable to NERC RRO and require RRO to oversee the process of maintaining an accurate national model or equivalents that can be used between Regions. Anything less than this is placing an unfair burden and unrealistic expectation on the TO to produce and maintain an accurate model for interconnecting Protection System Studies. 6. A dispute resolution mechanism also needs to be required to provide for instances where entities cannot come to a mutual agreement. Recommend a requirement be included for entities to request applicable RC(s) to arbitrate to bring resolution to a matter.

Response: Thank you for your comment.

1. **The drafting team has modified Requirement R1, Part 1.1 to read "Perform a Protection System Study for each Interconnected Element to coordinate Protection Systems, such that the least number of power system Elements are isolated to clear Faults as follows:" to be consistent with the Purpose.**
2. **Requirement R1, Part 1.1.2 provides for a time frame to complete a Protection System Study once a notification that the short circuit current at an Interconnected Element has changed. Requirement R2 provides for a periodic review of short circuit currents. This standard will retain this requirement.**
3. **The drafting team recognizes there are variations of margins used throughout the industry; however, the drafting team believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.**
4. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed**

Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: “Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.” **5. The drafting team believes that individual entities are not responsible for regional models, they are responsible for conveying information on their own equipment and system** **6. The drafting team believes that any conflict resolution should be handled through normal company practices. The drafting team cannot make judgments on compliance.**		
Texas Reliability Entity		1. Requirement R1.1.3: While we agree with the SDT rationale that R3 notifications may occur weeks or years prior to the change, we feel that a time frame should be included in this requirement rather than leaving it open-ended. 2. We suggest that the Protection System Study be completed at least 60 calendar days prior to the in-service date for R3.1 and within 30 days after receiving notification for R3.3. If the SDT agrees with this, then an appropriate VSL should also be drafted.
Response: Thank you for your comment. **1. The drafting team believes there in not a single time frame that would be appropriate for every project and has chosen to not add a time frame.** **2. Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.”. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**		
Associated Electric Cooperative, Inc., JRO00088		1. See SERC Comments 2. Also pertaining to PRC-027-1 Page 2, Terms:, "Interconnected Facilities" definition, proposed change: Replace: “functional, operating, or corporate entities” with: “functional or operating entities” Rationale: In certain cases,

		independent Corporate entity is irrelevant to the planning and operations of these systems. As written, the underlying 6 G&Ts of AECI's JRO could technically and unnecessarily be subjected to this standard for AECI's internal Facilities, and not just Interconnected Facilities between AECI and other non-JRO entities, although AECI's JROs functionally coordinate relay settings much as a large IOU's regional departments would.
Response: Thank you for your comment. **1. See response to SERC Comments.** **2. Based on comments, the drafting team changed Interconnected Facilities to Interconnected Elements defined as follows, Interconnected Elements: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity.**		
Western Small Entity Comment Group		The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.
Response: Thank you for your comment. **The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
PPL Corporation NERC Registered Affiliates		The cutoff date of 6/18/07 for grandfathering of studies may be appropriate for TOs and DPs in light of changes over time to their systems, but the studies that originally established GO relay settings would still be valid where the equipment has stayed the same. For the reasons discussed above, there should be no applicability of PRC-027 to independent GOs, and no changes to PRC-001-1.1 because the applicable requirements.
Response: Thank you for your comment. **The drafting team modified Requirement R1, Part 1.1.1 to make studies performed prior to 6/18/07 acceptable if the Protection System Study summaries contain the minimum attributes described in Requirement R1, Part 1.2. which now reads: "Provide to**		

the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each Protection System Study."The drafting team believes the applicability of PRC-027-1 is correct and the applicability of PRC-001-3 as revised is correct.		
Santee Cooper		1. The documenting, notification and replies required in this standard will put a significant strain on the time of settings personnel. While we agree that this coordination of data is very important, any simplification of the processes would help ensure that protection system staff has the time to do other critical protective system work, in addition to interconnection studies. 2. Possible suggestions would be change R2 2.1 to a longer time period, since most re-coordinations are due to changes covered in R3. "Not less than once every third year," would fall in well with the audit schedule. Not less than once every fifth year would match TPL-001-2 draft 5. 3. Also, you could conceivably not have R3 3.3, since those are covered by the statements in 3.1 and 3.2
Response: Thank you for your comment. **1. The drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. The drafting team is not requiring a Protection System Study; only a summary of the results of the Protection System Study performed is required to be provided to the other entities. The drafting team believes the scope of a particular project will dictate the work necessary to coordinate the Protection Systems involved, and to document the coordination process.** **2. The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate as is described in the Rationale for Requirement R2 and in the Guidelines and Technical Basis for Requirement R2. The TPL-001-2 short circuit analysis is for the purpose of assessing device interrupting ratings and is required to be performed annually (Requirement R2, Part 2.2). The part that you referenced does allow for extending the assessment in Requirement R2, Part 2.2 to five years (or even longer) but it is not an automatic extension. The drafting team points out that the Planning Assessments are performed for the Near Term Planning Horizon, which includes out-year simulations, which this standard does not require.** **3. Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed**		

Requirement R4, Part 4.3. The intent of Requirement R3, Part 3.3 is to communicate changes to a Protection System (including those discovered during an investigation) to an Interconnecting Entity as follows: "Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components."		
Duke Energy		1. The order of the Requirements in PRC-027-1 should be put in chronological order to align with the Example Process outlined on page 22. 2. PRC-001-1:It's not clear that balloting for Project 2007-06 also includes PRC-001-3. 3. General comment - The vague language of R1 does not make it practicable for the responsible entities to implement the requirement. 4. The Purpose is limited to coordination/relationship with the applicable entities. The Purpose is vague as to whether it applies to the Bulk Electric System. 5. Requirement R1 does not clearly state a reliability outcome/benefit. It is not aimed to achieve one objective. The phrase "shall be familiar with the purpose and limitations of protection system schemes," is vague and not measurable. What does it mean to be "familiar" with in this context? Could this requirement be stated in a way that is measurable? The outcome is not obvious because of vague terminology. What will be the outcome of entities being "familiar purpose and limitations of protection system schemes?" The term "familiar" is too general to address a single activity. Although it can be inferred that familiarity with the purpose and limitations helps ensure reliability, what single reliability goal will be accomplished? 6. There is no measure specified for R1 (according to the Model: each requirement must have one or more associate measures used to objectively evaluate compliance with the requirement). What type of evidence could be used so the entities are compliant with the requirement? The Data Retention language mirrors the recommended default language. However, because there are no measures, which are "used as a guide in identifying which

		responsible entity must keep the evidence and for how long," where do the "3 years" come from? There is no supporting document or reference to a supporting document for justification of VRFs for PRC-001-3; although, there is one for PRC-027-1 (which does not mention PRC-001-3).No explanation is given for the "High" or "Severe" VRF for R1.Generally, how is the VSL said to be "Severe" if there are no measures for R1? Effective Date - There needs to be an explanation for the time lapse of more than 3 months between approval date and the effective date of the standard. Additional clarity is needed regarding performance requirements and how an entity would demonstrate compliance with R1.Requirement R1 doesn't support the Purpose statement of the standard.

Response: Thank you for your comment.

1. **The standard has been reviewed by NERC Quality Review for format and content. The Example Process is intended to present one scenario, and the drafting team has decided not to change it.**
2. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
3. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
4. **It is unclear to the drafting team whether your comment references PRC-001-3 or PRC-027-1. However, the drafting team has revised the Purpose statement in PRC-027-1. The new Purpose statement reads: To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults.**
5. **This drafting team is not addressing the refinement of PRC-001-3. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
6. **Based on comments, the drafting team modified the Facility Applicability 4.2 to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements,"**

which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.		
Wisconsin Electric Power Company		1. The SDT is to be commended for their efforts in what is a very challenging standard to develop. 2. A Protection System Study by definition must assure that Protection Systems are “coordinated” at an Interconnected Facility. However, this standard does not establish any ownership for achieving a complete study. The interconnected entities are only capable of studying the portion of the system that they own. So, each entity performs their portion of the study and communicates it to the other entities. Thus, there is a lack of clarity in the standard about how the complete study gets done and is documented. With the possible exception of the Transmission Owner, no entity alone has the complete system model that is essential for documenting the complete coordination study. 3. There is also ambiguity on what a complete study looks like, and is subject to interpretation. It is unclear how the supplementary documents previously developed for PRC-001 apply to this standard. In the absence of such guidance, how will consistency be achieved for coordination of Protection Systems on the various types of Interconnection Facilities ? 4. It is suggested that Requirement R4.3 is extraneous and should be removed. If these changes are sufficient to trigger a study, then the timeframe for agreement is already specified in R4.1. We propose that the standard be revised to allow the entities to re-affirm the results of a previous study, when appropriate, rather than needing to perform another study. For example, perhaps the fault current has increased, but the coordination interval between devices is not appreciably changed. 5. The SDT notes in several places in the draft standard (pg 6, 16) that there is no evidence of widespread miscoordination between Interconnected Facilities, nor any evidence of misoperations caused by lack of coordination. 6. This suggests that if this standard is needed, that it should be simpler, less

		prescriptive, and have greater recognition of the motivation for mutual coordination that already exists. It can be argued that the tasks and time frames required in the draft standard should be left to the entities to determine.
Response: Thank you for your comment. 1. **Thank you for your support.** 2. **It is expected that the owner of the Interconnected Element will complete the Protection System Study for that element. See the Figures 1-5 and accompanying explanations.** 3. **The drafting team is not defining what every Protection System Study should look like, just the minimum that must be included into a summary that will be provided to the Interconnected Element Owner.** 4. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.** 5. **PRC-027-1 is replacing Requirements R2 and R3 of PRC-001-2. The drafting team is developing a standard based on a SAR accepted by the Standards Committee and is addressing directives issued by FERC in Order 693.** 6. **The drafting team believes that there is flexibility in the process to allow for the expertise of each entity to be used to coordinate Protection Systems.**		
ISO RTO Council SRC		The SDT recognizes that Requirement R1 falls outside the scope of Project 2007-06 and proposes that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. Left unaddressed, entities may be reluctant to vote to approve the PRC-001-2 changes. Changes made to a standard can cause unforeseen or unintended consequences that cannot be addressed because of limitations in the scope of the project. The SDT has no ability to address the matter without getting a change in scope of the project. This is a concern that applies to ALL standards changes as the industry seeks to revise and improve the NERC standards. A change in the Rules of Procedure or the Standards Development Procedures must be in place to recognize and deal with such occurrences. The SDT (SRC?) is also concerned that these proposed requirements are not

		conducive to NERC's stated goal of making the reliability standards more "results or performance oriented". Although many of the actions embodied in the proposed requirements should be performed, they are administrative in nature and do not in and of themselves provide results that will impact reliability. The industry needs to discuss and come to agreement on what reliability standards should look like in order to meet the NERC stated goal. The SRC also believes these requirements are not applicable for entities operating in the ERCOT Interconnection.
Response: Thank you for your comment. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".** **The drafting team believes the documentation identified in the requirements is necessary to support the purpose.** **The drafting team believes PRC-027-1 applies to all applicable entities that own Protection Systems within ERCOT.**		
MWDSC		The standard requires more documentation than is necessary and providing a copy of each Protection System Study is burdensome and would not result in better performance. It should be adequate to document that studies were performed and that affected entities have agreed to the results.
Response: Thank you for your comment. **The wording of Requirement R1, Part 1.2 is "Provide to each affected Interconnected Element owner a summary of the results of each Protection System Study performed pursuant to this requirement…" Transmitting the entire PSS is not required. The receiving entity per Requirement R4 Part 4.1 shall "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required."**		
Colorado Springs Utilities		1. The wording of the text under Applicability suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are often located in different functional or

		corporate entities we feel this would require more documentation, and therefore needs clarified. 2. There are no specifications on what constitutes a significant change to a Protection System; is it a CT ratio change, a relay replacement, or anything to the whole system? For example, would a single structure replacement require notification as a line spacing change? The wording sounds good but lacks specifics that would make this a workable standard.
Response: Thank you for your comment. **1. The standard is only applicable to Distribution Providers with "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements."** **2. The drafting team believes when changes that "modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements", they must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that "Changes to a transmission system Element that changes any sequence or mutual coupling impedance" and therefore would be included in the communication.**		
ATCO Electric		There are too many timelines that are hard to keep up with. The drafting team should reduce amount of timelines to a manageable amount.
Response: Thank you for your comment. **The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**		
Liberty Electric Power LLC		There is no generator size limit set for this standard. It should exclude generators below a threshold value. Suggest generators with an aggregate nameplate value below 500 MVA connecting through a single step-up transformer.
Response: Thank you for your comment. **The drafting team has modified the Applicability Section 4.2 Facilities to read: "Protection Systems installed for the purpose of**		

detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements". Consequently, the standard is applicable to Generator Owners that have the Facilities described above.		
Portland General Electric Company		1. This standard, as written, requires an inordinate amount of documentation that this not in line with current fault study and protection coordination tools. When combined with the timelines, this will require a complete rework of the existing processes used for protection coordination and an additional full time protection engineer. We have no history of misoperations on interconnecting lines or of backup protection on such lines to justify any additional effort to document coordination. 2. R1 leaves open to interpretation what constitutes coordination, with many unanswered questions. What is an acceptable coordination margin? How many contingencies need to be considered? Does loss of communication need to be considered? For the evidence, would an exception report showing no coordination intervals are violated be acceptable for the "summary results of each Protection System Study"? 3. Will the responsibilities outlined in the Application Guidelines be included as part of the final standard? These may not be in line with current practices. How will this requirement be audited across utilities with different coordination practices? 4. R2 requires significant cooperation between interconnecting utilities, with each keeping track of what fault currents are being used by the other. This is not in line with the use of joint system models, allowing more frequently updated fault currents to be used. Currently, the individual system models are updated by some utilities daily then they are reconciled at least annually. Protection System Studies can be run any time in between model reconciliation, with all local changes accounted for. 5. R3.1 does not provide guidance on the timing of notification for changes; the measure M6 indicates this is for future changes, but the requirement does not.

		6. Protection engineers are rarely notified in advance of transmission line changes resulting from such things a road widenings and pole replacements. Providing this information to neighboring utilities in advance will require significant changes to line design processes. Thresholds must be established to rule out minor transmission line changes that do not significantly impact the line impedance (and thus the fault current); perhaps a 10% change in impedance would be more appropriate than the general "changes to line lengths and/or conductor size or spacing". 7. This requirement should also include changes to facility ratings to ensure PRC-023 compliance. 8. R4 requires a significant change to work practices to support capital construction schedules and allow interconnecting utilities 30 days to review changes. The schedule laid out does not account for disagreements that lead to back-and-forth prior to achieving agreement. This requirement grants power to neighboring utilities to halt construction activities which could, in turn, create compliance violation of other Reliability standards.

Response: Thank you for your comment.

1. **The drafting team will continue to restrain the number of timelines, however the drafting team believes that changes affecting Protection Systems must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained.**
2. **It is up to the Owner to determine what margins are appropriate for their system and under what contingencies the relays should coordinate.**
3. **The Application Guidelines are and will be part of the standard and are consistent with the requirements of the standard. The figures in the Application Guidelines are intended to be explanatory.**
4. **The drafting team believes that the 24 month fault current review for Protection System coordination purposes is appropriate. This does not preclude an entity from performing this task more often.**
5. **The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated.**

6. The drafting team believes when a change "modifies the conditions used in the coordination of Protection Systems of the Interconnected Elements", it must be communicated to the interconnecting entity to ensure that Protection System coordination is maintained. For the example cited in the comment, Requirement R3 Part 3.1 states that "Changes to a transmission system Element that change any sequence or mutual coupling impedance" and therefore would be included in the communication. **7. The drafting team believes that FAC-009 already requires the sharing of Facility Ratings and their inclusion into the Protection System coordination standard is unnecessary.** **8. Based on comments, the drafting team revised Requirement 4, Part 4.1 to read: "Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required." Based on comments, the drafting team revised Requirement R4, Part 4.2 to read: "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes.**		
American Electric Power		1. We agree with the comment in the background section that the SAR written for this project was focused on System Protection Coordination, and we recommend that PRC-001 R1 should be moved to another standard more focused on operations or training. TOP-006 R3 might be a more appropriate standard for such a requirement. 2. For R1, the standard needs to clearly state the boundaries of the required study(ies). In addition, detail is needed regarding the depth of study away from the point of interconnection, and how far into the generating unit auxiliary system or interconnecting system must be evaluated. 3. Based on the redline provided where R3 and R4 have been removed, and assuming the SDT is not willing to moving the sole remaining requirement to another standard, the title and purpose of resulting PRC-001 would need to be changed. 4. If PRC-001 R1 remains as it is, the phrase "familiar with the purpose and limitations of protection system schemes" needs additional clarity. Doing so might help prevent a CAN from being developed to provide such clarity.

		5. AEP suggests the time requirement on R4.3 associated with R3 needs to be extended to 60 days.

Response: Thank you for your comment.

1. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
2. **Based on comments, the drafting team modified the Facility Applicability 4.2 to "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements", which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard.**
3. **This drafting team is not addressing the refinement of PRC-001. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-3, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
4. **This drafting team is not addressing the refinement of PRC-001-3 Requirement 1. As noted in the background section, "The SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new standard".**
5. **Based on comments, the drafting team combined Requirement R3, Parts 3.3.1 and 3.3.2 into Part 3.3, and removed Requirement R4, Part 4.3.**

Consumers Energy		1. We feel that this is a very difficult standard to interpret consistently as written. We think a negative vote is warranted since it is confusing and unclear for our situation. Following are specific comments to support our negative vote. 2. In regard to the Process Flow Chart on page 21 - We assume this Process Flow Chart is intended as an illustrative clarification of the standard, not a supplement to the wording. The chart claims to be a "complete representation of the process" and as such should match identically or it should be eliminated as it causes confusion. It is our interpretation that the chart does not match the standard's wording. One example if you start with an R3 emergency replacement you end up with two conflicting results.

		Under 4.3.2 you have 30 days to confirm that the changes are acceptable. Under 1.1.3 you have to do a protection study so you are given 90 days per section 1.2. This entire chart should be verified to ensure that it matches the written standard and does not result in conflicting requirements. We suggest adding the sub-requirement labels to each flow chart item for easier reference to that section of the standard. 3. In regard to Figure 3 on page 25 - The figure appears to represent the connection of a large NERC qualified generator. Does this figure also apply to a looped source distribution system or should that follow figure 4? We would like to see a definitive example that clarifies what to do for the situation where you have a looped source distribution system. 4. In regard to Figure 4 on page 26 - the figure implies that A & B can be set to overtrip C (as no study is required) which would interrupt the BES for distribution faults. This appears to be contrary to what is intended by this standard.
Response: Thank you for your comment. **1. The drafting team is striving to improve the standard through the balloting process.** **2. The drafting team has modified the flowchart based on comments and to reflect all changes made to the standard.** **3. Figure 3 is represents a generator connected to a Distribution Provider. The drafting team modified Figure 3 to indicate that the source could be a generator or a network system. The Applicability Section 4.2 Facilities states: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements", which the team believes clarifies those Protection System Elements that are required to be coordinated under this standard. This does not include a Protection System that would operate for a Fault on the Transmission System, if that is not its primary purpose. Figure 4 is intended to be a radial Distribution System with no source.** **4. Figure 4 is intended to illustrate a situation where no Protection System Study is required per this standard because there is no Protection System installed to detect Faults on the BES Transmission System. This does not preclude the Transmission Owner from reviewing the Protection System to ensure the system operates as designed.**		
Public Service Enterprise		We have the following additional comments:

Group		a. FORMATTING: Remove the bullets in 3.1 and replace with subparts 3.1.1, 3.1.2, etc. b. With regard to R2, we suggest that the Transmission Planner be required to perform the studies described therein, not the TO. c. Furthermore, there should be a requirement similar to that suggested in our response to #5, paragraph that each TP provide data needed by another TP needed to perform the required study. It should also address how potentially different results for the same Interconnected Facility by the several TPs should be dealt with.
Response: Thank you for your comment. **a. The drafting team has retained the format for Requirement R3, Part 3.1.** **b. Although the Transmission Planner may "define system protection and control needs", it will be the owner that is responsible for determining the implementation and coordination.** **c. The drafting team believes that nothing in the requirements precludes an entity from asking for necessary data, and requirements are needed to ensure that requested data is provided. The drafting team believes that communication between interconnecting entities is important for any change that modifies the information used to comply with Requirement R2. The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon.**		
Public Utility District No. 1 of Snohomish County		We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I".**		
Sacramento Municipal Utility District		We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I.
Response: Thank you for your comment. **Per your suggestions and others, the drafting team has modified the equation to replace "V" with "I".**		

Tri-State G & T		We think there needs to be a time frame associated with the calculation of the percent deviation after the fault duties are calculated. One way to accomplish that would be to eliminate 2.1 and add a 24 month requirement to 2.2., which would require the performance of a short circuit study anyway.
Response: Thank you for your comment. **The drafting team believes that the phrase "pursuant to Requirement R2, Part 2.1, using the following equation" implies that the calculation must be performed within the same 24 month period. As stated in the Rationale box supporting Requirement R2, Part 2.1: "Short circuit databases are customarily updated annually, so the SDT believes 24 months provides the entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation."**		
NV Energy		While we agree the Protection System Studies are necessary to verify coordination of Protection Systems, we believe that the proposed Standard requires more than the necessary amount of documentation, and therefore becomes administratively burdensome. This is contrary to the principles of the Results-Based Standards. We suggest that the evidence be limited to evidence that studies were coordinated and that the applicable entities have agreed to the results of the studies.
Response: Thank you for your comment. **The drafting team believes that documentation is necessary in order to have a record that the coordination study was completed, communicated to the appropriate Entities and agreed upon. Requirement R4 Part 4.2 has been modified to read "Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, confirm the owner(s) of each Facility associated with the affected Interconnected Element accept any resulting Protection System(s) changes." The measure for Part 4.2 is M9, which now reads "Acceptable evidence for R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that confirmation of agreement was achieved prior to implementation of any planned Protection System(s) changes."**		
Exelon		None

END OF REPORT