Consideration of Comments on 1st Draft of PRC-002-2 — Disturbance Monitoring and Reporting Requirements — Project 2007-11

The Disturbance Monitoring Standard Drafting Team thanks all commenters who submitted comments on the proposed first draft of reliability standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements. This standard was posted for a 45-day public comment period from February 2, 2009 through March 18, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 62 sets of comments, including comments from more than 130 different people from over 70 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.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 609.446.9723 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

The responses and proposed changes below were developed by the previous Drafting Team prior to the Project being moved to informal development in the Fall of 2010. The suggested changes to the Standard may not reflect the vision of the current Drafting Team, but the Drafting Team has taken them into consideration while drafting in the latest version of the Standard. The Project moved to formal development in January of 2013. The Drafting Team will be holding a Webinar and Workshops to bring the industry up to speed on the Project and to obtain feedback.

In drafting the second version of this standard, the SDT considered the following issues:

The SDT decided to develop requirements for functionality for Disturbance data recording, rather than to require specific equipment. The team focused on the “what” is required rather than describing “how” it is to be done.

The Disturbance data requirements are focused on

- Sequence of events
- Faults
- Dynamic disturbances

[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/pa/Stand/Resources/Documents/Appendix3AStandardsProcessesManual.pdf

The requirements can be met by a variety of equipment.

The SDT re-introduced the requirements for maintenance and testing of disturbance recording systems in the proposed standard. The SDT is proposing that the responsible entities establish and utilize a maintenance and testing program that contains specific items. Maintenance and testing requirements that are currently part of the FERC approved standard, PRC-018-1 – Disturbance Monitoring Equipment Installation and Data Reporting Requirement R6 will be replaced by the requirements in the proposed PRC-002-2.

During the first posting, the majority of commenters either suggested alternate equipment location criteria or requested technical justification for the proposal in draft 1 of the standard. In response to this feedback, the SDT conducted an analysis of short-circuit MVA data using data submitted voluntarily by several utilities. The criterion used by the SDT in selecting locations for monitoring/recording Disturbance data is based on an analysis conducted by the team in 2009-2010. Please review the technical paper posted with the standard that summarizes the analysis.

The SDT removed the proposed IEEE definition for sub-station due to comments received in the first posting. The SDT also included definitions for Disturbance Monitoring Equipment (DME), Sequence of Events (SOE) recorder, Fault Recorder (FR), and Dynamic Disturbance Recorder (DDR). The definition for DME exists in the NERC Glossary of terms but will be replaced by the proposed definitions when the proposed standard is approved.

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	Rick White	Northeast Utilities	NPCC	1
3.	Randy MacDonald	New Brunswick System Operator	NPCC	2
4.	Manny Couto	National Grid	NPCC	1
5.	Ralph Rufrano	New York Power Authority	NPCC	5
6.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
7.	Michael Sonnelitter	NextEra Energy	NPCC	5
8.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
9.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Brian Evans-Mongeon	Utility Services	NPCC	6
14.	Michael Gildea	Constellation Energy	NPCC	6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Xiadong Sun	Ontario Power Generation Inc.	NPCC	5
16.	Lee Pedowicz	NPCC	NPCC	10
17.	James Ingleson	New York Independent System Operator	NPCC	2
18.	Paul Kiernan	New York Independent System Operator	NPCC	2
19.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
20.	James Delorme	Nova Scotia Power, Inc.	NPCC	2
21.	Gerry Dunbar	NPCC	NPCC	10

				1	2	3	4	5	6	7	8	9	10
2.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Anita Lee	AESO	WECC	2
2.	Patrick Brown	PJM	RFC	2
3.	Bill Phillips	MISO	RFC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Jim Castle	NYISO	NPCC	2
6.	Matt Goldberg	ISO-NE	NPCC	2
7.	Charles Yeung	SPP	SPP	2

				1	2	3	4	5	6	7	8	9	10
3.	Group	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
4.	Group	Donald Davies	Members of the WECC Disturbance Monitoring Work Group										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Pink	TSGT	WECC	1
2.	Doug Selin	APS	WECC	1, 3, 5
3.	Gary Kopps	NV Energy	WECC	1, 3, 5
4.	Peter Mackin	USE	WECC	
5.	Steve Rueckert	WECC	WECC	NA

6.	Donald Davies	WECC	WECC NA
7.	Kenneth Wilson	WECC	WECC NA

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Busbin	Southern Company - Transmission	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Raymond Vice	Southern Company Services	SERC	1
2.	Hugh Francis	Southern Company Services	SERC	1
3.	J. T. Wood	Southern Company Services	SERC	1
4.	Marc Butts	Southern Company Services	SERC	1
5.	Bill Shultz	Southern Company Services	SERC	5
6.	Phil Winston	Georgia Power Company	SERC	3
7.	Steve Bennett	Georgia Power Company	SERC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Scott Goodwin	Midwest ISO	SERC	2
4.	Carter Edge	SERC Reliability Corp	SERC	10
5.	Pat Huntley	SERC Reliability Corp	SERC	10
6.	Bob Jones	Southern Co. Services	SERC	1
7.	David Marler	TVA	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Steve Waldrep (Co-Chair), Joe Spencer (SERC staff)	SERC Protection and Controls Sub-committee										X
8.	Group	Sandra Shaffer	PacifiCorp	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Jalal Babik	Dominion	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc	RFC	5, 6
2.	Mike Garton	Dominion Resources Services, Inc	NPCC	5, 6
3.	Tommy Owens	ELECTRIC TRANSMISSION RELIABILITY	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Burns	Transmission Technical Operations	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Bill Duge	FE	RFC	5
3.	Jim Detweiler	FE	RFC	1
4.	Art Buanno	FE	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Silvia Parada-Fortun	Florida Power & Light	X		X		X					
13.	Group	George P. Nino	Los Angeles Department of Water & Power	X				X				X	
14.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

6.	Jim Haigh	WAPA	MRO	1, 6
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Joseph Knight	GRE	MRO	1, 3, 5, 6
9.	Scott Nickels	RPU	MRO	3, 4, 5, 6
10.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
11.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
12.	Pam Sordet	XCEL	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Ed Taylor	PG&E System Protection	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vahid Madani	PG&E	WECC	1
2.	Steven Ng	PG&E	WECC	1
3.	Chifong Thomas	PG&E	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Individual	Joe Uchiyama	US Bureau of Reclamation					X				X	
17.	Individual	Robert W. Cummings - Director of Event Analysis	NERC										
18.	Individual	Jian Zhang	TransAlta					X					
19.	Individual	Joe White	Grant County PUD	X		X							
20.	Individual	Jeremiah Stevens	NYISO		X								
21.	Individual	Gary Preslan/Bill Middaugh	Tri-State Generation and Transmission Association	X		X		X	X				
22.	Individual	Russell A. Noble	Cowlitz County PUD	X		X	X	X					
23.	Individual	Adam Menendez	Portland General Electric	X		X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Dania J. Colon	Progress Energy Florida	X		X		X					
25.	Individual	Catherine Koch	Puget Sound Energy	X									
26.	Individual	Lance Irwin	Schneider Electric										
27.	Individual	Dan Rochester	Independent Electricity System Operator		X								
28.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
29.	Individual	Michael Sonnelitter	NextEra Energy Resources (formerly FPL Energy)					X					
30.	Individual	Manuel Couto	National Grid	X		X	X						
31.	Individual	Kris Manchur	Manitoba Hydro	X		X		X	X				
32.	Individual	John Gyrath	Exelon Generation LLC					X					
33.	Individual	Scott Helbing	NV Energy	X		X	X	X					
34.	Individual	Dave Szulczewski	DTE Energy/Detroit Edison			X							
35.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
36.	Individual	Jack Soehren	ITC Transmission, METC	X									
37.	Individual	Alan Gale	City of Tallahassee (TAL)	X		X		X					
38.	Individual	Alvin C. Depew	PHI (PEPCO Holdings Inc.)	X		X							
39.	Individual	Richard Salgo	NV Energy (fka Sierra Pacific	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
			Resources)										
40.	Individual	John Hernandez	Salt River Project	X		X		X				X	
41.	Individual	John F. Hauer	Pacific Northwest National Laboratory									X	
42.	Individual	Jerry Blackley	Progress Energy Carolina, Inc.	X		X		X					
43.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
44.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
45.	Individual	Steve Rueckert	WECC										X
46.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
47.	Individual	Rick White	Northeast Utilities	X									
48.	Individual	Randy Schimka	San Diego Gas and Electric Co.	X		X							
49.	Individual	Gregory Campoli	New York Independent System Operator		X								
50.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
51.	Individual	Douglas Selin	Arizona Public Service Co.	X		X		X					
52.	Individual	Charles J. Jensen	JEA	X		X		X				X	
53.	Individual	John Tolo	Tucson Electric Power	X									
54.	Individual	Anita Lee	Alberta Electric System Operator		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Murty Yalla	Beckwith Electric Co										
56.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
57.	Individual	Armin Klusman	CenterPoint Energy	X									
58.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
59.	Individual	R. Peter Mackin, P.E.	Utility System Efficiencies, Inc.										
60.	Individual	Dan Buchanan	British Columbia Transmission Corporation	X									
61.	Individual	Tim Hinken	Kansas City Power & Light	X		X		X	X				
62.	Individual	Richard Curtner	PNM										

1. The SDT has considered the "fill in the blank" items that are specified in the NERC Board approved standard PRC-002-1 that the Regional Reliability Organizations were required to develop "procedures and requirements" for the entities to meet. The SDT also considered all the directives specified in FERC approved PRC-018-1. The SDT is proposing to change the "fill in the blank" characteristics into entity specific requirements and merge them with the PRC-018-1 requirements. The new proposed standard PRC-002-2 contains all requirements related to disturbance monitoring with the exception of maintenance and testing (see Question #3 below). Do you agree with the SDT's proposal to develop and merge all disturbance monitoring requirements into a new PRC-002-2?

Summary Consideration: Commenters generally agreed with the SDT proposal to retire PRC-018-1 (except for Testing and Maintenance requirements) and merge those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2. Commenters also agreed with the proposal to replace the "fill in the blank" requirements with entity specific requirements.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
Response: The SDT thanks you for your comment. Your assumption is correct. The SDT proposes and discusses in the Implementation Plan the retirement of PRC-018-1 (except for Maintenance and Testing requirements) and the merger of those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2.		
SPP System Protection and Control Working Group	Yes	Please clarify the term "entity specific requirements" in Question #1.
Response: The SDT thanks you for your comment. Entity specific requirements are requirements in a standard that apply to entities that are the relevant functional entities as described in the Functional Model. In the case of the proposed standard, the relevant functional entities to which the standard requirements apply are the Planning Coordinator, the Transmission Owners and the Generator Owners.		
Members of the WECC Disturbance Monitoring Work Group	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company - Transmission	Yes	Southern Company agrees with the comments made by the SERC Protection and Control Subcommittee (PCS). Generally, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid. These stability evaluations should be made according to an overall NERC defined methodology. In the absence of a NERC defined methodology, a SAR should be introduced to produce one.
Response: The SDT thanks you for your comment. The drafting team has made revisions and has related location determination to the results of short circuit study for the area of the system relevant to the functional entity. New proposed criteria for Sequence of Events (SOE) and Fault Recorder (FR) data requires that monitoring be installed on 20% of the bus locations with the highest calculated three-phase short circuit MVA within the Planning Coordinator's fault study area at 1500 MVA or above, as calculated under normal configurations and connected at a 100 kV or higher voltage. In addition there is are new proposed criteria for Dynamic Data Recorder (DDR) data that requires monitoring be installed on 5% of bus locations within a Planning Coordinator's area that includes bus locations with the highest calculated three-phase short circuit MVA at 1500 MVA or above, connected at 100kV or higher and includes generators with a nameplate rating of 1000 MVA or above, or for an aggregate nameplate rating of 1000 MVA or above with a common point of interconnection as identified by the Planning Coordinator's study.		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	But we believe that the regional "Stability" group needs to decide on the locations of the DDR's based on a NERC defined methodology.
Response: The SDT thanks you for your comment. Based on industry comments, the SDT revised the DDR requirement in the latest revision of proposed R17 to reflect current practice for determining DDR location requirements by assigning responsibility to the Planning Coordinators. Planning Coordinators are required to establish a list of DDR monitored locations every five years that includes 5% or the bus locations within the Planning Coordinator's area. The new proposed criteria for DDR requires monitoring be installed on 5% of bus locations within a Planning Coordinator's area that includes bus locations with the highest calculated three-phase short circuit MVA at 1500 MVA or above, connected at 100kV or higher and includes generators with a nameplate rating of 1000 MVA or above, or for an aggregate nameplate rating of 1000 MVA or above with a common point of interconnection as identified by the Planning Coordinator's study. Requirement R23 requires that the Transmission Owners and Generator Owners record DDR data at the locations specified by the Planning Coordinators.		
PacifiCorp	Yes	
Bonneville Power	Yes	Is there a purpose to the analyses proposed. How much detail is really needed?

Organization	Yes or No	Question 1 Comment
Administration		
Response: The SDT thanks you for your comment. The purpose of the standard is "To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)"; therefore, the standard only establishes requirements for data collection and does not define how the data will be used or the extent of the analysis.		
FirstEnergy	Yes	We agree that it will be beneficial to consolidate these standards into one document.
Response: The SDT thanks you for your comment.		
Florida Power & Light	Yes	A single standard to define the installation application of DMEs makes good sense.
Response: The SDT thanks you for your comment.		
US Bureau of Reclamation	Yes	It is good idea to make a single document to cover all DME requirements
Response: The SDT thanks you for your comment.		
Cowlitz County PUD	Yes	A single standard addressing disturbance monitoring is GREATLY appreciated. This will simplify compliance efforts.
Response: The SDT thanks you for your comment.		
City of Tallahassee (TAL)	Yes	Any time we can combine similar requirements into the same standard we are better off.
Response: The SDT thanks you for your comment.		
PHI (PEPCO Holdings Inc.)	Yes	No need for different standards to cover DM.

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks you for your comment.		
Pacific Northwest National Laboratory	Yes	The new standard should at least allude to the context within which the data will be employed, and to the data quality (resolution, accuracy, band shape) that is requisite to this usage. (Data rates derive from the needed quality.) To do this for DDR devices the new standard must somehow encapsulate core issues that are addressed in documents [21,125,221]. [21] Integrated Dynamic Information for the Western Power System: WAMS Analysis in 2005, J. F. Hauer, W. A. Mittelstadt, K. E. Martin, J. W. Burns, and Harry Lee in association with the Disturbance Monitoring Work Group of the Western Electricity Coordinating Council. Chapter 14 in the Power System Stability and Control volume of The Electric Power Engineering Handbook, edition 2, L. L. Grigsby ed., CRC Press, Boca Raton, FL, 2007. [125] WECC Disturbance/Performance Monitor Equipment: Proposed Standards for WECC Certification and Reimbursement, Principal Investigator K. E. Martin. Draft report of the WECC Disturbance Monitoring Work Group, March 17, 2004.[221] PMU System Testing and Calibration Guide. NASPI report of the Performance & Standards Task Team (PSTT), December 30, 2007.
Response: The SDT thanks you for your comment. The purpose of the standard is “To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)”; therefore, the standard states requirements only for data collection and does not define how the data will be used or the extent of the analysis. The SDT believes that the granularity of data specifications may vary greatly depending upon the analysis tools selected and by vendors of monitoring equipment. The SDT has addressed what must be done, and does not specify how it is to be done.		
Hydro-Québec TransEnergie	Yes	We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
Response: The SDT thanks you for your comment. Your assumption is correct. The SDT proposes and discusses in the Implementation Plan the retirement of PRC-018-1 (except for Maintenance and Testing requirements) and the merger of those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2.		
WECC	Yes	I also agree with changing the fill in the blank characteristics into entity specific requirements
Response: The SDT thanks you for your comment.		
Progress Energy Florida	Yes	
Los Angeles Department of Water & Power	Yes	

Organization	Yes or No	Question 1 Comment
NYISO	Yes	
Puget Sound Energy	Yes	
PG&E System Protection	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Tri-State Generation and Transmission Association	Yes	
NERC	Yes	
Schneider Electric	Yes	
Grant County PUD	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
IRC Standards Review Committee	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 1 Comment
National Grid	Yes	
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
Exelon Generation LLC	Yes	
ITC Transmission, METC	Yes	
DTE Energy/Detroit Edison	Yes	
NV Energy	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
E.ON U.S.	Yes	
Progress Energy Carolina, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Co.	Yes	
JEA	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	
CenterPoint Energy		
TransAlta		

2. The SDT has developed a mapping document showing the requirements in PRC-002-1 and PRC-018-1 and where, in proposed PRC-002-2, those requirements are reflected (except maintenance and testing – see Question #3 below). Do you agree that the SDT has reflected all the appropriate requirements of PRC-002-1 and PRC-018-1 in the proposed PRC-002-2?

Summary Consideration: Commenters generally agreed that the mapping document demonstrated that all the appropriate requirements of PRC-002-1 and PRC-018-1 (except maintenance and testing) have been reflected in the proposed PRC-002-2.

Note that PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT has advanced the date to be reasonable with any installations needing revision.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for recording devices installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 applies to the installation of DDR devices after Jan. 1, 2011. Why was the date changed? In PRC-002-1 R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Data file naming, and data file formatting should be a requirement.
Response: The SDT thanks you for your comment. PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of "what" is required but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
FirstEnergy	No	We agree that maintenance and testing requirements might eventually be more appropriately located in another standard at some future time. However, in order to retain the current approved standard requirements that include

Organization	Yes or No	Question 2 Comment
		maintenance and testing, these requirements need to be included in this standard until such time they can be transferred to another standard. Otherwise, the SDT should provide a technical justification as to why these requirements are no longer needed for this type of equipment.
Response: Please see the response provided for this same comment repeated in question #3.		
MRO NERC Standards Review Subcommittee	No	In the proposed PRC-002-2 R8 (DDR), why did the SDT drop the requirement for single generators to be 500 MVA or higher as noted in the Applicability section 4.2
Response: The applicability section 4.2 states that PRC-002-2 applies to generator owners. The SDT realized generator nameplate rating for a single unit 500 MVA or higher is a requirement and should be placed in the requirement section of the standard. Requirements specific to generator MVA are stated in the revised draft standard.		
City of Tallahassee (TAL)	No	Current "Requirements" R4 should NOT be moved to the Compliance section. This will result in missing requirement. This is hiding a requirement in Compliance or Monitoring and is a practice we need to get out of! Compliance sections 1.3.1, 1.3.2, and 1.5.1 need to be moved back into the Requirements section!
Response: The purpose of this standard is to ensure that disturbance data is available. The conditions under which the data is used, why it is used, and by which entity it is used are as diverse of the range of disturbances and system configurations. Since neither this standard, nor its predecessors, established "what" analyses are required and by which entity they were required, it was not possible to establish reporting "requirements" which are really a matter of "how" the available information can be communicated. Compliance can use information communicated to a requesting entity to verify that the required data was actually available. The SDT believes that the information being "moved" to the compliance section is not requirements, but is part of compliance elements that relate to the requirements.		
Hydro-Québec TransEnergie (HQT)	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for recording devices installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 applies to the installation of DDR devices after Jan. 1, 2011. Why was the date changed? In PRC-002-1 R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Data file naming, and data file formatting should be a requirement.
Response: PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant		

Organization	Yes or No	Question 2 Comment
situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of "what" is required but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
Northeast Utilities	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for continuous recording for DDRs installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 delays this requirement until Jan. 1, 2011. Why was the date changed? In PRC-002-1, R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Will this be enforced as a "Requirement"?
Response: PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of "what" is required but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
E.ON U.S.	No	The SDT appears to have exceeded what is necessary by requiring all GOs and TOs to provide this information. Compliance with these draft requirements promises to be extremely costly. It is a major undertaking for all Generation Operator's across the nation to install synchronized disturbance monitoring devices capable of recording down to +/- 2 milliseconds. Also, there should be allotted more time for the engineering and installation of new hardware, etc. than that provided in the proposed timetable
Response: The SDT thanks you for your comments. Only those GOs and TOs that are identified on the list of locations for which SOE, FR, or DDR functionality must be provided will be required to provide the information. The SDT believes that will be approximately 20% of the locations for SOE and FR, and 5% for DDR. The +/- 2 millisecond requirement is not a new requirement (it was in FERC approved PRC-018-1, Requirement R1.1). The proposed implementation schedule is consistent with PRC-018-1 and with PRC-002-1.		
Southern Company - Transmission	Yes	No further comment.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comment.		
SERC Protection and Controls Sub-committee	Yes	Except possible impact based on protection scheme used when three phase line or bus potential are not available.
Response: The SDT thanks you for your comment. Protection schemes are not addressed in this standard. The standard is intended to outline the requirements for DME; it is up to the individual entity to ensure that DME will not interfere with the functionality of their protection schemes.		
JEA	Yes	Good job on mappring all the requirements!!
Response: The SDT thanks you for your comment.		
US Bureau of Reclamation	Yes	
Los Angeles Department of Water & Power	Yes	
Dominion	Yes	
American Electric Power	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
Cowlitz County PUD	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	
Tri-State Generation and Transmission Association	Yes	
DTE Energy/Detroit Edison	Yes	
NYISO	Yes	
NERC	Yes	
Schneider Electric	Yes	
NV Energy	Yes	
PG&E System Protection	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Entergy Services, Inc	Yes	
Independent Electricity System Operator	Yes	
ITC Transmission, METC	Yes	
Exelon Generation LLC	Yes	

Organization	Yes or No	Question 2 Comment
San Diego Gas and Electric Co.	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
New York Independent System Operator	Yes	
IRC Standards Review Committee	Yes	
SPP System Protection and Control Working Group	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
Xcel Energy	Yes	
Kansas City Power & Light	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Wisconsin Electric	Yes	

Organization	Yes or No	Question 2 Comment
PNM	Yes	
Portland General Electric		
Salt River Project		
British Columbia Transmission Corporation		
Pacific Northwest National Laboratory		
PacifiCorp		
Grant County PUD		
CenterPoint Energy		
National Grid		
Arizona Public Service Co.		
Utility System Efficiencies, Inc.		
WECC		
Members of the WECC Disturbance Monitoring Work Group		
TransAlta		

3. The SDT recommends that the maintenance and testing requirements for disturbance monitoring equipment belong in another standard. Do you agree with the SDT's proposal to exclude these requirements from PRC-002-2 and include them in another standard, either through the creation of a SAR or by assigning these requirements to an existing project?

Summary Consideration: Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2, Requirement R27. Eventually, a new SAR will be proposed and the requirements related to disturbance monitoring equipment will be fully developed and assigned to another standard.

Organization	Yes or No	Question 3 Comment
Southern Company - Transmission	No	Southern Company does not agree with separating from this standard maintenance and testing requirements for disturbance monitoring equipment for inclusion in another standard. We feel that separating those requirements needlessly complicates an entity's ability to monitor and maintain compliance with the standard(s). We realize the drafting team is handling a set of very technical and complex issues in this disturbance monitoring and reporting standard and we urge them to keep the standard simple where possible.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
SERC Protection and Controls Sub-committee	No	Prefer that M&T continue to be contained within this standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
Dominion	No	Prefer M&T to be contained within this standard. Do not move DME M&T to a totally new standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	No	We agree that maintenance and testing requirements might eventually be more appropriately located in another standard at some future time. However, in order to retain the current approved standard requirements that include maintenance and testing, these requirements need to be included in this standard until such time they can be transferred to another standard. Otherwise, the SDT should provide a technical justification as to why these requirements are no longer needed for this type of equipment.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
US Bureau of Reclamation	No	As I mentioned in item-1 above, all DME requirements should be in one document. The maintenance and testing requirements for DME should be in one document.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
Progress Energy Florida	No	Requirements related to DME equipment maintenance should not be included in the PRC-005 standard because the importance of DME equipment does not warrant the same high level attention as Protection Systems. PRC-002-2 seems to be a more logical place.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
DTE Energy/Detroit Edison	No	One standard should cover all issues relating to disturbance monitoring. Also, since DMEs are monitoring and not protective devices, is it necessary to specify maintenance/testing requirements? Requirements already in the Standard for data submittals would necessitate maintaining the availability of the DMEs.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
ITC Transmission, METC	No	The FERC-approved PRC-018-1 requires a maintenance and testing program for DME and it should be

Organization	Yes or No	Question 3 Comment
		included in the new PRC-002-2.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
Progress Energy Carolina, Inc.	No	Requirements related to DME equipment maintenance should not be included in the PRC-005 standard because the importance of DME equipment does not warrant the same high level attention as Protection Systems. PRC-002-2 seems to be a more logical place.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
WECC	No	I agree with the notion that the maintenance and testing requirements for disturbance monitoring equipment belong in another standard. However, I am concerned that if they are not initially included PRC-002-2, that for a while we run the risk of not having a standard that requires maintenance and testing of disturbance monitoring equipment. I am concerned that an effort through creation of a SAR or assigning these to an existing project may take longer than completion of the proposed PRC-002-2. Would it be possible to retain the existing requirment for the applicable entity to have a maintenance and testing program that includes maintenance and testing intervals and their basis, and a summary of maintenance and testing procedures (PRC-018, R6) in PRC-002-2 until such time that a replacement standard was approved, and then drop the requirement from PRC-002-2?
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
E.ON U.S.	No	All requirements relating to DME (disturbance monitoring equipment) should be set forth within one standard. The SDT should add the maintenance and testing requirements as well. For utilities that may well have to invest considerable sums of money in the procurement and installation of new equipment, an awareness of any maintenance and testing requirements will allow for better informed, more cost effective procurement decisions
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT		

Organization	Yes or No	Question 3 Comment
proposes temporarily addressing these requirements in PRC-002-2.		
Xcel Energy	No	Even though there may be some overlap in hardware between DME and protection systems, we believe the maintenance requirement should be driven by the equipment function and impact on grid reliability. (Disturbance Monitoring Equipment should not be treated the same as protection system relays.) The PRC-002-2 SDT is in the best position to make that determination and specify maintenance requirements for DME.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Northeast Power Coordinating Council	Yes	We agree that the maintenance and testing should be in another standard. However, we are concerned that the time to develop a separate standard would introduce a "time gap" when there would be an in force Disturbance Monitoring Standard, with no document in place addressing maintenance and testing.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
IRC Standards Review Committee	Yes	The SRC agrees with the proposal to exclude maintenance and testing from this standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
SPP System Protection and Control Working Group	Yes	Recommend to include these requirements in PRC-005 (with time line) or a specific action plan with time line (parallel to PRC-002-2) to include in another standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Florida Power & Light	Yes	Maintenance can be defined in another standard, however, PRC-002 should specifically allow for missing data for a given event since triggering may be inadequate and equipment can be down for maintenance/repair.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
MRO NERC Standards Review Subcommittee	Yes	Having a separate maintenance and testing standard may be easier to administrate for most utilities.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
NERC	Yes	They should be included in PRC-005 -- Transmission Protection System Maintenance and Testing
Response: The SDT thanks you for your comment and for your suggestion. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Cowlitz County PUD	Yes	Maintenance and testing (M&T) separation is good as long as there is no text in either standard referring back to another standard. So, PRC-002-2 has recording parameters defined as it should; the M&T standard should only require the equipment to be maintained (keep it working) and tested (it works as programmed). If the installed equipment does not meet the requirements of PRC-002-2 either by wrong choice of equipment or poor programming, then there is only a PRC-002-2 violation, not a PRC-M&T standard violation as long as the equipment was maintained and tested. In other words, a single violation should only incur one standard being violated; standard verbiage should avoid the possibility of double jeopardy. I would suggest that the same SDT for PRC-002-2 work on the M&T standard.
Response: The SDT thanks you for your comment. The SDT agrees with your description of the appropriate separation of concepts. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
American Electric Power	Yes	AEP is agreeable that the maintenance and testing belongs in another standard. Currently, there is a maintenance and testing team at work on standard PRC-005-1 (Project 2001-17) wherein these requirements would fit well.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment		

Organization	Yes or No	Question 3 Comment
belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
City of Tallahassee (TAL)	Yes	It would be ideal if ALL Maintenance and Testing requirements were in one standard!
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
NV Energy (fka Sierra Pacific Resources)	Yes	The maintenance and testing requirements do not belong in this Standard. However, since the devices' performance is not a system protection function, I believe that there should not be any NERC Standards/Requirements for maintenance and testing requirements. If deemed necessary, it would suffice to have a performance standard that requires that the appropriate data be available and collected from the disturbance monitoring equipment following system events, rather than imposing another set of maintenance requirements on the industry. To the extent that some of the disturbance monitoring functions are carried out by actual protective relays; example, SEL relays, then the maintenance of the protective functions of those relays will already be covered in PRC-005.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Pacific Northwest National Laboratory	Yes	Testing requirements must, among other things, verify that the hetterogenous sets of DDR data can be integrated and processed in a timely manner--e.g., the DDR types must in some sense be "interoperable." This will lead to desirable performance targets that should be incorporated into standards for future DDR installations. (See various documents on the WECC WAMS.)
Response: Data file formatting is not the subject of “what” is required by the standard but a matter of “how” processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
Hydro-Québec TransEnergie (HQT)	Yes	We agree that the maintenance and testing should be in another standard. However, we are concerned that the time to develop a separate standard would introduce a "time gap" when there would be an in force Disturbance Monitoring Standard, with no document in place addressing maintenance and testing.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment		

Organization	Yes or No	Question 3 Comment
belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
JEA	Yes	Protective relays based on microprocessor technology support SOE and DFR functionality, along with the ability to directly interface with local GPS satellite clocks for very accurate recording of events and faults. These SOE and DFR capabilities are programmed with the same software progams that "protection engineers" use to program settings and logic. The Protection System Maintenance and Test Project may be a better location to contain the maintenance requirements for SOE and DFR functionality provided by microprocessor protective relays. If Test and Maintenance requirements for the "same box" are developed independently of the PSMT Project, there is a distinct possibility of conflicting maintenance and test requirements for the "same box" and also the possbility of "double jeopardy" when it comes to VSLs and other auditable compliance criteria. DDR, PMU and legacy SOE, DFR and DDR maintenance and test requirements could be developed in alignment with other test and maintenance requirements through joint coordination between the DMSDT and PSTMSDT, or another SAR and new SAR team may need to be formed with team members from both a DM backgound and Protection Systems background to develop comprehensive maintenance and test requirement for DM equipment.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Utility System Efficiencies, Inc.	Yes	I agree with this proposal. However, I would suggest that current maintenance and testing requirements at either the NERC or RRO level be maintained until the new maintenance and testing standards are approved and in effect. In other words, don't eliminate any current requirements between now and the time new maintenance and testing requirements are put in place.In addition, testing requirements must, among other things, verify that the heterogenous sets of DDR data can be integrated and processed in a timely manner--e.g., the DDR types must in some sense be "interoperable." This will lead to desirable performance targets that should be incorporated into standards for future DDR installations. (See various documents on the WECC WAMS.)
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
Kansas City Power & Light	Yes	The current Reliability Standard PRC-005 for maintenance and testing of system protection systems may not be a good place for maintenance and testing of Disturbance Monitoring Equipment (DME). The maintenance and

Organization	Yes or No	Question 3 Comment
		testing requirements for DME are not the same as for system protection systems and for that reason it is not recommended to mix them with PRC-005 if that was being suggested by the SDT. Protective relaying may not operate between maintenance cycles, however, that is typically not the case for DME operation. Maintenance should not be required if a DME triggers and correctly captures a record on a regular basis. Do not disagree with the concept of of a separate standard for the maintenance and testing for DME.
Response: The SDT thanks you for your comment. The SDT does not, in its proposal, intend a "mix" of disturbance monitoring requirements with system protection requirements; rather, the SDT intends for the specific requirements for each type of function to be covered. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Bonneville Power Administration	Yes	
Los Angeles Department of Water & Power	Yes	
Grant County PUD	Yes	
Tri-State Generation and Transmission Association	Yes	
Portland General Electric	Yes	
Independent Electricity System Operator	Yes	
PacifiCorp	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Schneider Electric	Yes	

Organization	Yes or No	Question 3 Comment
Puget Sound Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
New York Independent System Operator	Yes	
NYISO	Yes	
San Diego Gas and Electric Co.	Yes	
PG&E System Protection	Yes	
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
Northeast Utilities	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy	Yes	
Entergy Services, Inc	Yes	
Arizona Public Service Co.	Yes	
Duke Energy	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	

Organization	Yes or No	Question 3 Comment
CenterPoint Energy	Yes	
Salt River Project	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
British Columbia Transmission Corporation	Yes	
Tucson Electric Power	Yes	
Wisconsin Electric	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
TransAlta		
National Grid		

4. The criteria used by the SDT in selecting locations for monitoring/recording Disturbance data is based on minimum number of elements (lines, transformers, etc.) or minimum amount of generation at a specific location. This approach facilitates the measurement of compliance to the requirements. Do you agree with the SDT's approach? Please provide specific comments, examples or recommendations.

Summary Consideration: Comments indicated that those who responded agreed with the intent of the standard. However, stakeholders pointed out that the wording of the requirements and tables required clarification. Additionally, commenters stated that the location criteria for DME seemed arbitrary, and asked what the drafting team's technical justification was for the location criteria. Some commenters stated that the use of the term "substation" presented in the requirements was misunderstood.

The drafting team undertook a significant rewriting of the draft standard. The requirements were made clearer and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received, the task team developed location criteria for SOE and FR data to be 20% of bus locations with the highest calculated short circuit MVA level. To address the misunderstanding of the use of the term "substation," the drafting team dropped the use of the term and focused on buses as a location criterion.

Organization	Yes or No	Question 4 Comment
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established new criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard.		
Duke Energy	No	We generally agree with the approach but refinements are needed. We suggest exempting 230 kV radial lines without transmission connected generation. Also do not include these radial 230 KV lines in the count of 3 or more lines for SER & DFRs and do not include in the count of 7 or more lines for DDRs.
Response: The SDT thanks you for your comment. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		

Organization	Yes or No	Question 4 Comment
CenterPoint Energy	No	In Table 4.1 for Fault Recording Data, the SDT has attempted, to a degree, to allow monitoring of a substation at the remote terminals to preclude the requirement of installing Fault Recording equipment at the substation. For example, the first bullet indicates Fault Recording is required for each transmission line that does not have fault data recorded at its remote terminals?. In the second bullet, however, if the substation has a transmission bus, such as in breaker-and-a-half configurations, fault recording equipment is required. CenterPoint Energy's believes fault data recorded at remote terminals is sufficient for analyzing bus faults and autotransformer faults. Similar to the first bullet in Table 4.1, CenterPoint Energy recommends adding that does not have fault data recorded at its remote line terminals to the end of the second and third bullets that refer to buses and transformers.
Response: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. The revised standard should ensure that sufficient elements are monitored. The team agrees that if no DME is installed at a terminal, but all remote terminals have DME that monitor the required elements, then no DME should be required at that particular terminal.		
E.ON U.S.	No	The SDT approach would in some instances require installation of redundant data monitoring equipment. One DDR per substation should be adequate; not one per generating unit.
Response: The SDT thanks you for your comment. The standard provides criteria for what elements to monitor. It does not specify the type or number of DME to be installed. How the elements are monitored is up to the TOs and GOs.		
Entergy Services, Inc	No	a) Simply specifying the number of elements may not be consistent with many existing Transmission Owner's historical DFR applicability criteria such as fault current availability and/or adjacent station coverage. A criteria consisting of a combination of the number of elements and a threshold short circuit MVA would be more appropriate for system coverage and yet still be measureable. Criteria should also include consideration for exceptions when there are adjacent station FRs in order to provide good system coverage and avoid unecessary redundant installations and expeditures. b) Also, the wording of R1.1 may does not seem be clear to everyone. Suggest the use of diagrams for clarity.
Response: The SDT thanks you for your comment. a) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard. b) The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the		

Organization	Yes or No	Question 4 Comment
requirements have been rewritten to provide clarification. The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard.		
Brazos Electric Power Cooperative, Inc.	No	The approach needs better engineering support of the criteria.
Response: The SDT thanks you for your comment. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. It is included in the revised draft standard.		
Pacific Northwest National Laboratory	No	While it may be convenient to enforce, the location criteria seem overly simplistic. Some locations are more important than others; the RRO is usually aware of them, and should be given discretion to set their monitoring requirements. Please note that the WECC places special emphasis upon the monitoring of major control systems, especially those for HVDC terminals and FACTS-like devices [123]. I strongly doubt that substation measurements on the ac side of these devices is sufficient to determine their behavior.[123] WSCC Plan for Dynamic Performance and Disturbance Monitoring, prepared by the WECC Disturbance Monitoring Work Group, October 4, 2000.
Response: The SDT thanks you for your comment. The drafting team understands your comment, however, in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. This standard will establish a baseline set of criteria and does not restrict the regions from having input into the location of DME.		
National Grid	No	Page 2, R1.1. of the mapping document as stated: R1.1. Contains any combination of three or more transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above, contradicts: Page 4 Table 4-1 Each Substation containing any combination of three (3) or more elements consisting of transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above. Further clarification is needed to avoid issues of interpretation.
Response: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
American Electric Power	No	AEP believes that there is some misunderstandings of the term "Substation" as applied in the standard. The

Organization	Yes or No	Question 4 Comment
		portion 'enclosed assemblage' is not clear enough to distinguish assets applicable to the standard. For example, distinct and separate busses, of differing voltage, that may be enclosed by a common fence. When Considered separately, one or the other separate busses may not meet requirement criteria, but considered combined, may meet criteria. When considered combined, AEP believes that the inclusion of additional facilities, simply because they are within the same fence, does not significantly enhance reliability as to be warranted.
Response: The SDT thanks you for your comment. Based on industry, feedback the SDT will not be using "substation" to define the locations. Instead, the standard uses the bus as a requirement in the location criteria.		
TransAlta	No	a)1. Selecting location for monitoring/recording disturbance data should be based on the disturbance analysis requirement as stated in the purpose section of this standard. But the SDT said," based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values will require significant additional resources". This statement does not fully match the purpose.b)2. Using the minimum number of elements or minimum amount of generation at a specific location has two deficiencies. Firstly, it may exclude some locations where it is critical for BES reliable operation but not under this minimum number criterion. Secondly, it may waster the resource in the case which the disturbance data are collected in two adjacent locations defined in the draft standard where there are elements between each other. So it is recommended that SDT review the approach and satisfy the purpose of this standard. It is better to provide some guideline to select the location, instead of use the number. Another suggestion is that SDT look at FERC approved standard EOP-004-1 disturbance reporting to determine how to select the locations for monition/recording disturbance data to facilitate the analysis of the events specified in EOP-004-1.3. c) Disturbance data are mostly used by the entities that have a wide area view such as RC. Normally, these entities decide where to collect disturbance data for analysis. The draft standard does not have such wordings which allow these entities to have inputs to choose the locations and elements.
Response: The SDT thanks you for your comment. a) The purpose of the standard is to establish the criteria for the monitoring of system elements for disturbance analysis. The requirements in the draft standard do offer guidance in selection of locations for DME. The drafting team understands that the requirements may represent a significant burden on resources; however, the purpose of the standard is to ensure that sufficient elements are monitored to facilitate the analysis of power system disturbances. b) Based on other comments received, the drafting team understands that certain elements may be excluded and there may be some adjacent locations that could have duplicate data. The drafting team also reviewed EOP-004-1 criteria and determined that it does not provide criteria for the selection of locations based on measureable criteria. c) Disturbance data includes sequence-of-events and fault data, along with dynamic disturbance data. Typically, an RC uses the dynamic disturbance data to analyze a disturbance, and a utility will use SOE and FR data. The original PRC-002 requires that the regional reliability organizations develop criteria for the		

Organization	Yes or No	Question 4 Comment
location of DME, which was rejected by FERC. However, in order to avoid a fill-in-the-blank standard, a defined set of criteria is required. The standard establishes this set of criteria, and it does not restrict the regions from having input into the location of DME.		
US Bureau of Reclamation	No	"or minimum amount of generation at a specific location." Whatever is this, I do not agree to have one recorder for many generator units. Every generator should have an own DME (such as capabilities of SER and Wave-Capture by a micor-processor relay).
Response: The SDT thanks you for your comment. The draft standard is focused on recording requirements and elements to be monitored, not the type of equipment or how each element is monitored. It is the responsibility of the TO and GO to decide what equipment to use and how they will meet the requirement.		
Los Angeles Department of Water & Power	No	Although we agree in principle with this criteria, establishing a substation voltage threshold at 200-kV creates specific problems for our utility. LADWP maintains a significant number of transmission lines and substations above 200-kV for supplying power around our large service area. Many of these stations are several buses away from interties with other utilities. We suggest that additional language be included in the proposed standards to exclude "internal-transmission lines" rated 200-kV and above from these regulations. Transmission lines and substations at or near intertie connections would still comply with proposed regulations. This proposed exclusion should have little to no impact on intertie data provided to NERC.
Response: The SDT thanks you for your comment. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		
SERC Protection and Controls Sub-committee	No	Agree with the approach given our understanding of thestandard's intent. a) The documents wording and Tables need to be clearerand more consistent. b) Suggest exempting 230 kV radial lines withouttransmission connected generation. Do not include these radial 230 KVlines in the count of 3 or more lines for SER & DFRs and do not includein the count of 7 or more lines for DDRs. c) It should be made clear thatthe equipment that must be monitored by a GO in Tables 2-1 and 5-1should be limited to equipment owned by the GO.Under Table 4.1, change the "and" below to "or." "Each Substation containing any combination of three (3) or more elements consisting of transmission lines operated at 200 kV or above and (change this "and" to "or") transformers having primary and secondary voltage ratings of 200 kV or above." Wording in Table 4.1 is more clear (assuming we understand the intent) than the wording in R1.1 and R1.2. We suggest that you use this clearer wording for these two requirements. d) We suggest that you make use of diagrams to make the intent clearer.
Response: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the		

Organization	Yes or No	Question 4 Comment
requirements have been rewritten to provide clarification. b) The drafting team agrees with your suggestion on excluding radial lines and has changed the wording of the requirements in the revised draft standard toaccount for this. c) The purpose of the standard is “To ensure that Facility owners, whether they are a TO or GO, monitor BES elements to ensure the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).” Based on comments received, the drafting team recognized that the tables contained in the draft standard were confusing and unclear. The tables have been eliminated from the revised draft standard. d) The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard.		
PacifiCorp	No	a) While this approach does facilitate the measurement of compliance, it does not necessarily effectively target those elements that have the greatest impact to the reliability of the Bulk Electric System. The critieria used should also include consideration of factors reflecting the importance or significance of the location to the power grid. For example: Radial taps should not be included as part of the three element requirement (minimum number of elements).
Response: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this		
Southern Company - Transmission	No	a) Southern Company supports the comments made by the SERC PCS. We urge the Drafting Team to utilize clarifying language in those areas identified in the comments of the SERC PCS. b) We are particularly keen on the idea of using diagrams to further clarify and illustrate the intent of the standard where needed. c) Southern Company disagrees with the use of arbitrary "checklist" values to determine location of disturbance monitoring equipment. As we commented in our response to Question #1, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. b) The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that		

Organization	Yes or No	Question 4 Comment
these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard. c) The drafting team understands your concern related to the location of disturbance monitoring equipment installed for the purpose of recording disturbance data,, and others share this concern. In order to develop a continent-wide standard, it is necessary to develop a set of measurable criteria.. The team's opinion is that if location of DME is done by stability study alone, it will not be measurable. The team elected to use a three-phase short circuit MVA criteria based on data voluntarily provided by utilities in different regions to determine monitoring requirements. The revised draft of the standard is based on this set of criteria.		
IRC Standards Review Committee	Yes	The SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."
Response: The SDT thanks you for your comment. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
Dominion	Yes	We agree with the approach given our understanding of the standard's intent. a) The wording in the requirements and the tables need to be clearer and more consistent. It should be made clear that the equipment that must be monitored by the GO in tables 2-1 and 5-1 should be limited to equipment owned by the GO. We suggest replacing the word its with Generator Owner , and that the Heading of Table 2-1 be re-labeled to indicate: for generating plant and substation equipment owned by Generator OwnerAs an example: We ask for clarification of the intent of the term generator output breaker b) Please refer to the following example: A GO owns a breaker on the low-side of the GSU which is used to synchronize the unit. The TO owns breakers on the high-side of the GSU. For the purpose of this standard which of these breakers is deemed to be the generator output breaker(s)We suggest clarifying that any references to a low-side breaker to only include low-side breaker used as generator output breaker. c) We suggest exempting radial lines without transmission connected generation. Do not include these radial lines in the count of 3 or more lines for SOE & FRs and do not include in the count of 7 or more lines for DDRs. Radial lines do not need to be monitored.
Response: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. b) The drafting team agrees with your comment regarding clarification of the generator output breaker. In the revised standard, it has added wording to clarify what the generator output breaker is, along with a statement confirming that it can be a low or high side breaker. c) The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	The element number criteria for SOE/FR/DDR needs to be adjusted (in general higher number criteria to not be burdensome to implement.). Also some stations that meet the proposed criteria are not as important, some that don't meet the criteria are. How many stations are impacted by SOE?
Response: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Florida Power & Light	Yes	Application of DMEs at the 200 kVand above is the correct voltage level to begin applying DMEs. However, substations with only three lines are approaching distribution size stations which would typically be served from larger stations that should be monitored. This would cause undue burdens on transmission owners. Although disturbances can begin at lower voltages they spread through the system at 200 kV and above. Moreover, any disturbance will always go back and be seen at the larger stations. Adequate data can be obtained at 200kV and above to determine system stability issues and frequency response.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established a revised set of criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard.		
PG&E System Protection	Yes	The Threshold for the number of elements is too low.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NERC	Yes	As written, R1.1 would require SOERs only at stations that have 3 transmission lines AND transformers. I'm sure that was not the intent. For clarity, R1.1 should be reworded to read (consistent with Table 4.1): Contains any combination of five or more transmission lines elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above.?
Response: The SDT thanks you for your comment. The drafting team recognized that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Grant County PUD	Yes	B.R1.1. I am unclear on this. The current language un-necessarily complicates things. I am concerned that the current wording could be interpreted to mean all locations with 3 T-Lines and any Xfmrs with any voltage greater

Organization	Yes or No	Question 4 Comment
		than 200kv.I would suggest that the wording from the left hand column of Table 4-1 be used here. Table 4-1: Wording in first paragraph in left column of table is inconsistent with B.R1.1 when describing elements to count. Also, third bullet in right column is inconsistent with Xfmr description in left column.
Response: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Tri-State Generation and Transmission Association	Yes	While we agree that using a minimum number of elements connected at some minimum voltage level is an appropriate method, we think that three elements may cause more substations to require the monitoring than is required to assure reliability.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Cowlitz County PUD	Yes	I believe the applicability thresholds as described in the proposed standard goes a long way in bringing a reasonable dividing line between responsible reliability monitoring versus over extension of applicability just to make sure all the bases are covered. Smaller entities who can not possibly impact the BES in any way (cascading failure) will be spared unnecessary compliance expense.
Response: Thank you for your positive comments.		
City of Tallahassee (TAL)	Yes	I agree with the approach. This approach makes it clear where it is needed, except as noted below.
Response: Thank you for your positive comments.		
Progress Energy Carolina, Inc.	Yes	These requirements will create consistancy in the required locations where the regions "opinions" are not different.
Response: Thank you for your positive comments.		
JEA	Yes	The choice of DFR data being derived from 200kV and above is a good selection from a continental standard perspective. The choice of 3 lines or greater provides for more coverage than is needed for DFRs. In some cases, 200kV 3 line substations will have very little impact on the overall bulk energy deleivery systems. In the cases where DDRs are located in close proximity to these 3 line 200 Kv stations, there should be allowances for

Organization	Yes or No	Question 4 Comment
		the fact that DDRs are covering the area and that DFRs may not be required from an additional data coverage standpoint.
Response: Thank you for your comments.		
Tucson Electric Power	Yes	Comment - For an interconnection point that is a transformer with the high and low side voltages exceeding 200kV and two different utilities owning the high and low side of the transformer, do both parties need to install monitoring equipment as described or does one utility take the responsibility for installing the monitoring equipment on either the high or low side winding?
Response: The SDT thanks you for your comment. The purpose of the standard is "To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)." Therefore, the standard only establishes requirements for data collection and does not define how the data will be used or the extent of the analysis. The opinion of the drafting team is that if dual ownership exists, the two companies may work out an agreement to address the requirements.		
Utility System Efficiencies, Inc.	Yes	While it may be convenient to enforce, the location criteria proposed can be overly simplistic. Some locations are more important than others; the RRO is usually aware of them, and should be given discretion to set their monitoring requirements. Please note that the WECC places special emphasis upon the monitoring of major control systems, especially those for HVDC terminals and FACTS-like devices. Substation measurements on the ac side of these devices may not be sufficient to adequately determine their behavior.
Response: The SDT thanks you for your comment. The drafting team understands your comment; however, in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. The standard will establish a baseline set of criteria and does not restrict the regions from having input into the location of DME.		
Members of the WECC Disturbance Monitoring Work Group	Yes	
SPP System Protection and Control Working Group	Yes	
FirstEnergy	Yes	
MRO NERC Standards Review	Yes	

Organization	Yes or No	Question 4 Comment
Subcommittee		
Portland General Electric	Yes	
Manitoba Hydro	Yes	
NV Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
NYISO	Yes	
Exelon Generation LLC	Yes	
Independent Electricity System Operator	Yes	
British Columbia Transmission Corporation	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Co.	Yes	
Xcel Energy	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 4 Comment
Wisconsin Electric	Yes	
Schneider Electric	Yes	
New York Independent System Operator	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Florida	Yes	
San Diego Gas and Electric Co.	Yes	
Beckwith Electric Co	Yes	
Salt River Project	Yes	
Alberta Electric System Operator	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Kansas City Power & Light	Yes	
Northeast Utilities		a) We agree that compliance must be measurable, and recognize also that it's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas. b) Also, in systems tightly networked at less than 200kV, it's possible for events to have significant impact on the EHV system, particularly under contingent conditions where EHV elements may

Organization	Yes or No	Question 4 Comment
		be out of service.
Response: The SDT thanks you for your comment. a) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. b) The team agrees with your comment; however, the team believes the revised standard will provide coverage for some buses at 100kV and above that could have a significant impact during events.		
Puget Sound Energy		
DTE Energy/Detroit Edison		
WECC		

5. In developing the Disturbance data requirements the SDT decided to focus on transmission voltage levels of 200 kV and above, generators 500 MVA and above, and generating stations 1500 MVA and above based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values to include the entire BES will require significant additional resources, while adding little value.

The proposed standard requires the following:

The status of GSU circuit breakers for generating plants connected at 200 kV and above shall be monitored on each generator with a nameplate capacity of 500 MVA or higher or an aggregate plant total of 1500 MVA or higher.

5.1 Do you agree with these nameplate values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration: Many stakeholders questioned the generator nameplate criteria. Some thought 500MVA and 1500MVA were too high, and some thought them too low. Commenters stated that the GO and TO responsibilities were not clear. In addition, as in question 4, commenters questioned the technical basis for the number of elements for SOE and FR.

The drafting team formed a task-team to develop a technical justification for location criteria for SOE, FR, and DDR functionality. This task team developed a set of criteria based on short circuit MVA and generator nameplate rating based on data supplied by several utilities. The draft standard was rewritten to incorporate the criteria as part of the requirements. In rewriting the standard, the drafting team eliminated the tables and modified the wording of the requirements. The new draft requirements clarify TO and GO responsibility.

Organization	Yes or No	Question 5.1 Comment
Northeast Power Coordinating Council	No	a) Performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. b) Monitoring should not be limited to breaker positions--this will improve event analysis. c) We do not feel that the 200kV threshold is an appropriate criteria for assessing criticality.
Response: Thank you for your comments. a) The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria. b) The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what		

Organization	Yes or No	Question 5.1 Comment
occurred during a wide area event. c) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
US Bureau of Reclamation	No	These capacites (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbacne analysis. These values should be 20MVA/unit and 75MVA/plant.
Response: Thank you for your comments. The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
NERC	No	Disagree with 200 kv and above...should be 100 kv and above.
Response: Thank you for your comments. The drafting team has changed the threshold to 100kV.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NYISO	No	We agree with these threshholds for some application of DME's, however for SOE requirements, we believe it should be reduced to 50MVA unit and 300MVA plant. Loss of generation affects the entire interconnection regardless of voltage level, and these levels are based on NPCC's current criteria. During a system wide event, many small generators may trip, and this generation adds up and is the reasoning behind monitoring smaller levels.
Response: Thank you for your comments. The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
NextEra Energy Resources (formerly FPL Energy)	No	In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
Response: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft		

Organization	Yes or No	Question 5.1 Comment
standard.		
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
Response: Thank you for your comments. The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured but can accomplish this through agreement with the TO that is monitoring the breaker.		
DTE Energy/Detroit Edison	No	"Aggregate plant total of 1500 MVA or higher" implies that several small generators, or peaking units, would have to be individually monitored if the total is 1500 MVA or higher. Suggest that 500 MVA be used as minimum generator size to be monitored.
Response: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Wisconsin Electric	No	We agree with these nameplate values for Sequence of Event data and Fault Recording data. However, the requirement for Dynamic Disturbance Recording data should have a higher threshold since it is a higher level monitoring equipment, looking at power swings instead of just fault data. We suggest that an aggregate nameplate rating of 2000 MVA is more reasonable. See #11 below.
Response: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Hydro-Québec TransEnergie (HQT)	No	a) Performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. Monitoring should not be limited to breaker positions--this will improve event analysis. b) We do not feel that the 200kV threshold is an appropriate criteria for assessing criticality whether as a lower limit or a higher one; in some system, not all 200 kV facilities and above are critical. A performance based stability studies can be used to determine the appropriate system that should be monitored.

Organization	Yes or No	Question 5.1 Comment
Response: Thank you for your comments. a) The drafting team understands your comment; however, in order to avoid a fill-in-the-blank standard a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. b) The drafting team understands that there are facilities at 200kV that are not critical and there are critical facilities at 100kV. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Northeast Utilities	No	See comments for question #4. Also, monitoring should not be limited to breaker positions; knowledge regarding what caused a generator to trip will improve event analysis.
Response: Thank you for your comments. The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what occurred during a wide area event.		
New York Independent System Operator	No	Loss of generation affects the system regardless of the voltage level the generator is connected. For Sequence of Events requirements, change units size to 50MVA, plant size to 300MVA, remove reference to connected at 200kV+ Change references to these levels for all Generator SOE requirements. See NERC 2003 Blackout Technical Report Recommendation TR-9
Response: Thank you for your comments. The drafting agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Beckwith Electric Co	No	a) Recommend changing it to: "The status of GSU circuit breakers and sequence of events data of protective relay operations at the generating plants with a name plate capacity of 50 MVA or higher or an aggregate plant total of 300 MVA or higher. "This will help possible future blackout investigations and improve generator - transmission system protection coordination for plants of significant size. b) This requirement should be based on

Organization	Yes or No	Question 5.1 Comment
		the plant size and not the connected transmission voltage.
Response: Thank you for your comments. a) The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what occurred during a wide area event. b) The drafting team believes that the standard criteria for generation is based on plant size where connected to transmission systems at 200kV and above. The standard does not prevent a region from developing more stringent criteria.		
IRC Standards Review Committee	Yes	As in the response to #4, the SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."
Response: Thank you for your comments. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
SPP System Protection and Control Working Group	Yes	Recommend to include GSU circuit breakers for generating plants connected at critical substations below 200kV. Recent disturbances in the SPP area have shown the need to include GSU circuit breakers for generating plants connected at less than 200kV.
Response: Thank you for your comments. The focus of the standard is monitoring of the bulk electric system. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Members of the WECC Disturbance Monitoring Work Group	Yes	We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV Is this standard applicable to this plant?
Response: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		

Organization	Yes or No	Question 5.1 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your positive comment.		
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response: Thank you for your comments. The standard applies to generation connected to the Bulk Electric System.		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed values seem to capture the generation facilities that would most likely have a BES reliability impact. However, we would like to better understand the technical rationale used by the SDT in choosing these values.
Response: Thank you for your comments. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response: Thank you for the positive comment.		
MRO NERC Standards Review Subcommittee	Yes	While the MRO NSRS does not disagree with the levels mentioned above, what is the technical basis for selecting those levels?
Response: Thank you for your comments. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
PG&E System Protection	Yes	We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to

Organization	Yes or No	Question 5.1 Comment
		record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV Is this standard applicable to this plant?
Response: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Cowlitz County PUD	Yes	For the WECC area, if we can't withstand a 1500 MVA loss without a cascading failure, then the system is operating too close to the line. I think the burden of proof should be on those who would argue for more stringent nameplate values.
Response: Thank you for your comments.		
Portland General Electric	Yes	The following are the comments of the DMWG which we are filing in support: We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Puget Sound Energy	Yes	We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments.		

Organization	Yes or No	Question 5.1 Comment
a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
American Electric Power	Yes	To provide better clarity of the requirement, it should be worded: The status of GSU circuit breakers for generating plants connected at 200 kV and above shall be monitored on each generator with a nameplate capacity of 500 MVA or higher, OR an aggregate plant total of 1500 MVA or higher AND CONNECTED AT 200kV AND ABOVE. AEP agrees with these nameplate values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response: Thank you for your comments. The standard has been reworded significantly since the prior posting.		
City of Tallahassee (TAL)	Yes	However, some confusion may be encountered when determining if it is a "plant" or "site" aggregate. Some utilities may not use the same nomenclature for each item. Two 900MW plants (or units) at one site should be captured, even though they are not a plant aggregate of 1500MVA.
Response: Thank you for your comments. If each plant has a single generator at 500 MVA or above, then each is required to be monitored. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Response: Thank you for the positive comment.		
Arizona Public Service Co.	Yes	a) There needs to be some consideration for generator owners who don't own/operate the switchyard that the generator circuit breaker is in as they may not have ready access to the breaker status for high speed recording and they may be beholden to the switchyard owner to get access. b) Also, a power plant with an aggregate of 1500 MVA or higher might only have a small portion of the generation connected at 200 kV and above. Those

Organization	Yes or No	Question 5.1 Comment
		portions not connected to the 200 kV and above system should not be required to meet the standard.
Response: Thank you for your comments. a) The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured, but can accomplish this through agreement with the TO that is monitoring the breaker. b) The standard applies to generation connected to the BES.		
Tucson Electric Power	Yes	We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Utility System Efficiencies, Inc.	Yes	I agree with the nameplate values. However, I have two questions. a) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. a) The GO would be responsible for working with the TOor other GO to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Southern Company - Transmission	Yes	No further comment.
Dominion	Yes	
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 5.1 Comment
PacifiCorp	Yes	
San Diego Gas and Electric Co.	Yes	
Independent Electricity System Operator	Yes	
Tri-State Generation and Transmission Association	Yes	
Grant County PUD	Yes	
Duke Energy	Yes	
Alberta Electric System Operator	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Carolina, Inc.	Yes	
Xcel Energy	Yes	
JEA	Yes	
Florida Power & Light	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5.1 Comment
Progress Energy Florida	Yes	
Salt River Project	Yes	
SERC Protection and Controls Sub-committee	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	
National Grid		
Brazos Electric Power Cooperative, Inc.		
Pacific Northwest National Laboratory		
WECC		
Schneider Electric		
CenterPoint Energy		

5.2 In part, Requirement R5 states that Fault Recording data shall be recorded at generating plants connected at 200 kV and above when a generator has a nameplate capacity of 500 MVA or higher or when there is an aggregate plant total of 1500 MVA or higher. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration: Commenters questioned the applicability of the standard to generators and the generator nameplate ratings in the criteria. They also questioned the technical justification for the criteria and recommended that bus voltage be monitored.

The standard does apply to generators connected to the BES system. The drafting team believes that monitoring the contributions from generators during a fault or wide area event will aid in the analysis of these events. The drafting team formed a task-team to develop a technical justification for location criteria for SOE, FR, and DDR functionality. This task team developed criteria based on short circuit MVA and generator nameplate rating based on data that was supplied by several utilities. The draft standard has been rewritten to incorporate the criteria as part of the requirements. The drafting team agrees that bus voltage should be monitored where applicable.

Organization	Yes or No	Question 5.2 Comment
US Bureau of Reclamation	No	These capacites (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbacne analysis. These values should be 20MVA/unit and 75MVA/plant.
Response: Thank you for your comments. Due to a lack of consensus from industry on generator size requirements for monitoring, the drafting team performed a study using data collected for the MVA study to determine what we think are appropriate generator nameplate ratings for monitoring. The data showed that appropriate criteria: 1- for SOE is the individual generators with a nameplate rating of 20 MVA or above or for an aggregate nameplate rating of 75 MVA or above connected to the facilities for FR is generators with a nameplate rating of 500 MVA or above, or for an aggregate nameplate rating of 500 MVA or above with a common point of electrical interconnection connected to the facilities contains DDR criteria for Generator Owners but does not include an MVA threshold.		
NERC	No	Disagree with 200 kv and above...should be 100 kv and above. It is important for forensic analysis to have both bus and line quantities for DFR quantities. Bullets 2 and 3 should read: On breaker-and-a-half arrangements, the outer bus voltages, and the individual line voltages.On straight buses, common bus voltages and the individual line voltages.
Response: Thank you for your comments. The drafting team does not agree that bus voltage is always required to perform a forensic analysis. For a breaker-and-a- half where each line has individual CCVTs for protection, bus CCVTs are typically not installed. For events, voltages from the lines can be used for any forensic analysis.		

Organization	Yes or No	Question 5.2 Comment
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
NextEra Energy Resources (formerly FPL Energy)	No	In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This included in the revised draft standard.		
DTE Energy/Detroit Edison	No	Please see comment for 5.1.
Response: Thank you for your comments. Please refer to our response for 5.1.		
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.
Response: Thank you for your comments. Please refer to our response for 5.1.		
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Arizona Public Service Co.	No	This should only be required for new plants that meet the criteria defined. Existing plants should be grandfathered. The other issues mentioned in Question 5.1 comments should also be considered and they are copied here: There needs to be some consideration for generator owners who don't own/operate the switchyard that the generator circuit breaker is in as they may not have ready access to the breaker status for high speed recording and they may be beholden to the switchyard owner to get access. Also, a power plant with an aggregate of 1500 MVA or higher might only have a small portion of the generation connected at 200 kV and above. Those portions not connected to the

Organization	Yes or No	Question 5.2 Comment
		200 kV and above system should not be required to meet the standard.
Response: Thank you for your comments. A requirement that applies to only new plants and grandfathers existing plants is not practical. Such a requirement could result in insufficient data for analysis during a wide-area event. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured, but can accomplish this through agreement with the TO that monitors the breaker. The standard applies to generation connected to the BES.		
Beckwith Electric Co	No	Recommend changing to: "Fault Recording data shall be recorded at generating plants when a generator has a nameplate capacity of 50 MVA or higher or when there is an aggregate plant total of 300 MVA or higher. "This will help possible future blackout investigations and improve generator - transmission system protection coordination for plants of significant size. This requirement should be based on the plant size and not the connected transmission voltage.
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard The drafting team believes that the standard criteria for generation is based on plant size where connected to transmission systems at 200kV and above		
Tucson Electric Power	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Utility System Efficiencies, Inc.	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
IRC Standards Review Committee	Yes	As in the response to #4, the SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."

Organization	Yes or No	Question 5.2 Comment
Response: Thank you for your comments. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
Members of the WECC Disturbance Monitoring Work Group	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		
Southern Company - Transmission	Yes	No further comment.
Response: Thank you for your comments.		
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your positive comments.		
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES. The standard applies to generation connected to the Bulk Electric System.		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed values seem to capture the generation facilities that would most likely have a BES reliability impact. However, we would like to better understand the technical rationale used by the SDT in choosing these values.
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the		

Organization	Yes or No	Question 5.2 Comment
location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response: Thank you for your positive comments.		
MRO NERC Standards Review Subcommittee	Yes	Why do the TOP with Frequency Recorders need to record Voltage line to neutral (R4 or R5.4) but the GO can read Voltage line neutral or Voltage line to line. (R5)?
Response: Thank you for your comments. The requirement is based on the typical connections found at TO facilities and GO facilities.		
PG&E System Protection	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Response: Thank you for your comments.		
Portland General Electric	Yes	The following are the comments of the DMWG which we are filing in support: What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Puget Sound Energy	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		

Organization	Yes or No	Question 5.2 Comment
American Electric Power	Yes	AEP agrees with these values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages that will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response: Thank you for your comments.		
City of Tallahassee (TAL)	Yes	This looks like the same as question 5.1. Are you asking if I agree with the 200kV threshold? If so, I agree, but I do not see the need to record the low side breakers per Table 2-1.
Response: Thank you for your comments. The format of the standard has been changed significantly since the prior posting.		
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Response: Thank you for your positive comments.		
Florida Power & Light	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Tri-State Generation and Transmission Association	Yes	
Salt River Project	Yes	
Progress Energy Florida	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 5.2 Comment
NYISO	Yes	
Dominion	Yes	
SERC Protection and Controls Sub-committee	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
PacifiCorp	Yes	
Wisconsin Electric	Yes	
Entergy Services, Inc	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
JEA	Yes	
Alberta Electric System Operator	Yes	

Organization	Yes or No	Question 5.2 Comment
Duke Energy	Yes	
SPP System Protection and Control Working Group	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Northeast Power Coordinating Council	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	
Grant County PUD		
National Grid		
Brazos Electric Power Cooperative, Inc.		
WECC		
Pacific Northwest National Laboratory		
Schneider Electric		

Organization	Yes or No	Question 5.2 Comment
CenterPoint Energy		

5.3 Requirement R7 states that DDR data shall be recorded or derivable for all substations having a total of seven or more transmission lines connected at 200 kV or above. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration: Comments stated that the substations with seven lines as a location criterion for DDR functionality was arbitrary and commenters asked about the technical justification for the criteria. Some suggested that DDRs be located by study rather than by the number of lines. Commenters stated that in general, fewer DDRs are required than FRs. In addition, commenters stated that radial lines should be excluded from the criteria.

The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. The number of circuits and the word substation was removed from the requirement.

Organization	Yes or No	Question 5.3 Comment
Southern Company - Transmission	No	Southern Company disagrees with the use of arbitrary "checklist" values for placement of DDR equipment. As we commented in our response to Questions #1 and #4, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response: Thank you for your comments. The drafting team acknowledges your concern, but in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, and that was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
SERC Protection and Controls Sub-committee	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002- 2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters Major voltage sensitive area Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas

Organization	Yes or No	Question 5.3 Comment
Response: Thank you for your comments. The drafting team acknowledges your concern, but in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, and that was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Dominion	No	Radial lines without transmission connected generation should not be included in the element count. Radial line feeding only load doesn't provide significant contribution to grid disturbances. Also we suggest rewarding R7 to: Each Substation having a total of seven or more transmission lines (not including radial Lines) connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data unless a Transmission Owner has Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4 recorded no further than two Substations away.
Response: Thank you for your comments. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Los Angeles Department of Water & Power	No	As stated earlier, LADWP distributes power around our service area at 230-kV. As a result, several of our transmission lines and substations fall within these proposed regulations yet have little influence on interties with other utilities. Additional language to exclude "internal transmission" resources from these regulations should be considered.
Response: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
NERC	No	For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1: “then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above a, the Transmission Owner shall record..."
Response: Thank you for your recommendation. The drafting team realizes the wording in the standard is not clear and has changed it for clarity.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. Please see our response to your Q4 comment.		

Organization	Yes or No	Question 5.3 Comment
Grant County PUD	No	R7 is very difficult to read. A reword similar to is suggested: When a Transmission owner DOES NOT have Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4, recorded no further than 2 Substations away, then.....
Response: Thank you for your comments. The drafting team realizes the wording in the standard is not clear and has changed it for clarity.		
Independent Electricity System Operator	No	In some areas of the interconnected network, there are substations that have fewer than 7 lines (typically 4 to 6 lines) connected to them. These areas might be sparsely populated but through them, transmission facilities are installed to facilitate transfer of remote resource to the load centres while supplying local area loads. Not having fault/disturbance recorders installed at these substations may create a void in the necessary data for event analysis. We suggest the SDT consider lowering the number to 4.
Response: Thank you for the recommendation. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Progress Energy Carolina, Inc.	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002- 2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters Major voltage sensitive areas Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas
Response: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.
Response: Thank you for your comments. Please refer to the response in Q5.1 above.		
Entergy Services, Inc	No	The number of lines criteria is too arbitrary and will require an excessive number of installations at some entities and

Organization	Yes or No	Question 5.3 Comment
		perhaps none at others. A better criteria is one that aligns with Regional needs and distributes these type of installations more evenly throughout the Region. Have the Regional Planning groups review and address where DDRs would be most effective and actually needed.
Response: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Arizona Public Service Co.	No	While the general premise might be acceptable, the Requirement R7 requires the DDR to monitor one phase current from every line operated 200 kV and above. This might not be possible or may be extremely difficult for some cases especially where the substation is jointly own/operated, is extremely large, or is quite old. The requirement should state a percentage of lines that must be monitored (say 50%).
Response: Thank you for your comments. The standard drafting team recognizes that it may be difficult to implement the criteria for the reasons stated. However, the drafting team believes the original criteria established are a good baseline to ensure that data is available for disturbance analysis.		
Duke Energy	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002-2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses of wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters? Major voltage sensitive areas Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas
Response: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
CenterPoint Energy	No	CenterPoint Energy disagrees that criteria for Dynamic Disturbance Recording (DDR) should be solely based upon the number of connected lines at a substation. In addition to the number of lines, CenterPoint Energy recommends that DDR equipment be required only in substations that have direct interconnections to generating units.
Response: Thank you for your comments. The drafting team disagrees with your recommendation to install DDR only at substations that have direct interconnections to generating units. DDR is typically installed at the points of a transmission system where a disconnect of load or generation would have a significant impact on system stability. This location may be far removed from where generation is directly connected to the transmission system. . The SDT		

Organization	Yes or No	Question 5.3 Comment
revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
IRC Standards Review Committee	Yes	The SRC agrees with the SDT decision to specify a common limit and recognize that special cases not covered by the common limit will be addressed by regional standards.
Response: Thank you for your positive comment.		
JEA	Yes	There is good correlation from multiple regions in support of the 200kV level and above for the busses that are considered the "most impactful" when considering major disturbances within a region. Busses that have a 10,000 MVA and above three phase short circuit capacity are significantly represented by 200kV and above criteria. When reviewing regional data for the 10,000 MVA and above three phase short circuit capacity, over 90% of those busses that are connected to generation, meet the 500/1500 MVA selected levels for generation, in support of the team's choice of these levels.
Response: Thank you for your comments.		
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your comments.		
Bonneville Power Administration	Yes	With coverage by FR and SOE, BPA does not think that DDR's are necessarily required at the same location. Their purpose is for overview devices and not as many may be required.
Response: Thank you for your comments. The drafting team agrees that fewer DDRs are required than SOE and FR.		
Florida Power & Light	Yes	We generally agree with this, however, it needs some defining.
Response: Thank you for your comments.		
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.

Organization	Yes or No	Question 5.3 Comment
Response: Thank you for your comments.		
American Electric Power	Yes	AEP agrees with these values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages that will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response: Thank you for your comments.		
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
US Bureau of Reclamation	Yes	
Portland General Electric	Yes	
PG&E System Protection	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 5.3 Comment
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	
Progress Energy Florida	Yes	
New York Independent System Operator	Yes	
San Diego Gas and	Yes	

Organization	Yes or No	Question 5.3 Comment
Electric Co.		
SPP System Protection and Control Working Group	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
PacifiCorp	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 5.3 Comment
PNM	Yes	
Northeast Utilities		We agree that compliance must be measurable, and recognize also that it's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas.
Response: Thank you. The drafting team agrees with your comments.		
Schneider Electric		
DTE Energy/Detroit Edison		
Brazos Electric Power Cooperative, Inc.		
WECC		
National Grid		
Pacific Northwest National Laboratory		
E.ON U.S.		

Requirements related to Sequence of Events

6. Requirement R3 states that Transmission Owners and Generator Owners shall record the time stamp or have a process in place to derive the time stamp to within four milliseconds of input received for the change in circuit breaker position (open/close) Do you agree with this value? If no, propose an alternate value and please provide technical basis.

Summary Consideration: Commenters suggested that R3 be separated into two requirements, one for TOs and one for GOs. They questioned the technical justification for the 4millesecond requirement, and found 4milleseconds in requirement R3 confusing when compared to the +/- 2milleseconds requirement in R12. Commenters also asked for clarification regarding TO and GO responsibility in relation to statements with the clause “process to derive.”

The drafting team discussed requirements R3 and R12 and determined that only one time stamping requirement was needed. Therefore, R3 was removed from the standard. R12 is now R1 and applies to both TOs and GOs. The drafting team does not believe that a separate time stamping requirement for TOs and GOs is needed. The drafting team also discussed the clause “a process to derive” at length, agreed that it was not clear, and changed the requirements appropriately. Rather than having a process in place to derive, the drafting team chose to require monitoring of electrical quantities in order to determine three-phase voltage and current of monitored elements. The drafting team believes that this clarifies the intent of the standard.

Organization	Yes or No	Question 6 Comment
SPP System Protection and Control Working Group	No	Please clarify and give examples of the "four milliseconds of input received" and "have a process in place to derive". What is the basis for choosing "four milliseconds" over "quarter cycle"? Please ensure that using relays for this requirement is sufficient.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Bonneville Power Administration	No	BPA believes 2-4 second SCADA/EMS records are good enough for most events.
Response: Thank you for your comments. The drafting team agrees that the 2-4 second SCADA/EMS records are generally good for most events, but as identified in the 2003 blackout report, it has been difficult to align the many events due to inconsistent time stamping. In the “August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts” report of February 10, 2004, Recommendation 12 states, “All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS).” The point of observation is typically at the substation; therefore, it is recommended that the time synchronization be applied at the substation. The +/- 2		

Organization	Yes or No	Question 6 Comment
millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
FirstEnergy	No	To allow for some flexibility and consistent with other requirements, we recommend replacing 4 ms with 1/4 cycle.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Tri-State Generation and Transmission Association	No	This wording seems very confusing. Does it intend to require that the time stamp will be recorded to indicate the time of the change in state of the breaker with an accuracy of +/- 4 milliseconds 2 millisecond resolution is required in R12. Is this inconsistent with that Requirement?
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
Independent Electricity System Operator	No	The disturbance monitoring function to which this time stamp refers is not obvious. From the flow of the requirements it appears to relate to sequence of events recording. If the requirement is indeed for the sequence of event recorder to mark a change in the status within 4 milliseconds of receiving an input of a change in the circuit breaker position, then the requirement should clearly state it is for the SOE recorder as otherwise, it will serve no purpose if the requirement is interpreted as applicable for a fault recording device. Further, please elaborate on the basis for the 4 ms.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
Response: Thank you for your comments. The requirements identify the responsible entities required to have the data. It is up to that responsible entity to determine how the data is generated.		
PHI (PEPCO Holdings Inc.)	No	The time should be listed as 1/4 cycle, since many relays specs indiacte 1/4 cycle for this requirement.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Kansas City Power & Light	No	Many protective relays sample inputs every quarter cycle, equivalent to 4.2 msec. Is the 4 msec requirement above intended to disqualify relays from being used as recording devices for breaker position? What is meant by a process in place to derive time stamp? Can examples be provided?
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
IRC Standards Review Committee	Yes	The SRC would suggest that Requirement 3 be separated into two independent requirements - one for TOs and one for GOs. Although the intent is to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R1 and R2 criteria.
Response: Thank you for your comments. The SDT agrees, and the revised standard has separate requirements for TOs and GOs where applicable.		
Southern Company - Transmission	Yes	Southern Company suggests the Drafting Team use their "reponses to comments" period to enlighten industry as to how a 4msec value was chosen for Requirement #4 and how a +/- 2msec value was chosen for Requirement #12.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
SERC Protection and Controls Sub-committee	Yes	Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
Florida Power & Light	Yes	However, please view our comments for question 17.
Response: Thank you. Please see response to question 17.		
Arizona Public Service Co.	Yes	This is not consistent with requirement R12 which states +/- 2 ms since within 4 ms means +/- 4.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
JEA	Yes	Local GPS satellite clocks are needed to properly time tag events and provide for correct data for analysis purposes. It should be noted that breaker mechanical contacts, "a" "b" "aa" and "bb", can be significantly outside of the range of 4 milliseconds in tolerance for certain types of breakers. A method to accommodate values outside the 4 millisecond range may need to be accomodated.
Response: Thank you for the comments. The standards requires timestamp of the mechanical contact locally but what type of contact is not defined.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Duke Energy	Yes	Suggest in R3, for consistency, use similar terminology to R 12 (where reference is +/- 2 ms).
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
Northeast Power Coordinating Council	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
PacifiCorp	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 6 Comment
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	
NERC	Yes	
Grant County PUD	Yes	
NYISO	Yes	
Cowlitz County PUD	Yes	
Portland General Electric	Yes	
Progress Energy Florida	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
Tucson Electric Power	Yes	
Beckwith Electric Co	Yes	
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
PNM	Yes	
E.ON U.S.		In answering this question, E ON US would benefit from knowing the SDT's technical basis for the 4 milliseconds
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
TransAlta		

Organization	Yes or No	Question 6 Comment
Schneider Electric		
Wisconsin Electric		
DTE Energy/Detroit Edison		
Los Angeles Department of Water & Power		
Puget Sound Energy		
WECC		
National Grid		
Pacific Northwest National Laboratory		
CenterPoint Energy		

Requirements related to Sequence of Events

7. Do you agree with the other Sequence of Events requirements under R1 through R3 of the proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration: The majority of commenters did not agree with SOE requirements under R1 through R3. Comments suggested increasing the number of lines criterion to a quantity of five or greater. Also, commenters suggested that the generator nameplate size requirements be lowered to 50 MVA unit or 300 MVA plant. Additionally, commenters stated that the location criteria seemed arbitrary and suggested that it be derived from stability studies of the electric grid with a NERC-defined methodology.

In response to these and other comments, the drafting team undertook a significant rewriting of the draft standard. The requirement language was changed for clarity and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received,the task team developed location criteria for SOE and FR data to be 25% of bus locations with the highest calculated short circuit MVA level.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions, protective relay tripping for all protection groups, and teleprotection keying and receiving.
Response: Thank you for your comments. The SDT believes that to establish SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis.		
IRC Standards Review Committee	No	The SRC agrees with the main requirement R1.However, the SRC does not agree with making R1.1 and R1.2 independent requirements. These two inclusions are explanatory text not specific ad hoc requirements. Note that in R2 the explanatory text is included in a Table not as independent requirements.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Members of the WECC Disturbance Monitoring Work Group	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at

Organization	Yes or No	Question 7 Comment
		200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Southern Company - Transmission	No	Southern Company disagrees with the use of arbitrary "checklist" values. As we commented in our response to Questions #1, #4 and #5.3, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response: Thank you for your comments. Please see our response for questions 1, 4, and 5.3. The SDT understands your concern related to the location of disturbance monitoring equipment and it is shared by others. In order to develop a continent-wide standard, it is necessary to develop criteria that are measurable. The team's opinion is that if location of DME is done by stability study alone, it will not be measurable. The team evaluated developing a location criteria using three-phase chort circuit MVA criteria based on data collected from select utilities in different regions to determine monitoring requirements. The revised draft of the standard is based on these criteria.		
SERC Protection and Controls Sub-committee	No	Reference comments on #4 above. Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Response: Thank you for your comments. Please see the response in #4. The +/- 2 millisecond is in reference to time stamping. The 4 millisecond requirement relates to ability of the recording equipment to recognize a change to an input status.		
PacifiCorp	No	Three or more lines connected to a substation does not clearly indicate impact or significance to the bulk electric system. Also see comment 4. above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. Also see the response to 4 above.		
Bonneville Power Administration	No	With relay based SOE/FR capability plus standalone, BPA believes 2-4 second SCADA/EMS records are good enough for most events. The number of element criteria may be too stringent, change to 5 elements.
Response: Thank you for your comments. The drafting team agrees that the 2-4 second SCADA/EMS records are generally good for most events, however, as identified in the 2003 blackout report, it was difficult to align the many events due to inconsistent time stamping. In the "August 14, 2003 Blackout: NERC Actions to		

Organization	Yes or No	Question 7 Comment
Prevent and Mitigate the Impacts of Future Cascading Blackouts" report of February 10, 2004, Recommendation 12 states; "All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS)." The point of observation is typically at the substation; therefore, it is recommended that the time synchronization be applied at the substation. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
PG&E System Protection	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NERC	No	R1.1As written, R1.1 would require SOERs only at stations that have 3 transmission lines AND transformers. I'm sure that was not the intent. For clarity, R1.1 should be reworded to read (consistent with Table 4.1):Contains any combination of five or more transmission lines elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above. Note the change from 3 elements to 5 elements...3 elements would require a significant number of new installations.
Response: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NYISO	No	For SOE requirements, we believe it should be reduced to 50MVA unit and 300MVA plant. Loss of generation affects the entire interconnection regardless of voltage level, and these levels are based on NPCC's current criteria. During a system wide event, many small generators may trip, and this generation adds up and is the reasoning behind monitoring smaller levels. Just monitoring breaker position isn't enough. The SOE should monitor CB position, protective relaying tripping of all protection groups, and teleprotection keying and receive. The 3rd and 4th row in the table puts the responsibility to monitor the transmission substation on the generation owner. This should be changed such that the station owner is required to monitor SOE at the substation. For monitoring the transmission substation SOE, we believe the 500MVA unit / 1500MVA plant, 200kV+ interconnection threshold is adequate.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis. The generation size requirements have been changed.		
Portland General Electric	No	The following are the comments filed by the DMWG which we are filing in support: The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Progress Energy Florida	No	Table 2-1 indicates "Including low side breakers" for plant SER data inputs. If an aggregate generation site of 1500MVA is monitored at the >200kV level where the generation enters the transmission network, the system impact of any occurrence will be seen at the monitoring point. PEF disagrees with the low side breakers position being included to be monitored by the DFR/SER. Monitoring of these breakers are included within the functional boundaries of the smaller generating units and the breaker voltages are less than 50KV and not part of the transmission grid. Extending this requirement will be costly since the DFR will be located at the transmission network location remote to the multiple generators and low side breakers. The requirement should only include the >200kV circuit breaker SER data.
Response: Thank you for your comments. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the circuit breaker that connects the GSU to the grid, the SDT believes it is reasonable to require monitoring on the low voltage circuit breaker.		
Puget Sound Energy	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		

Organization	Yes or No	Question 7 Comment
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
Response: Thank you for your comments. The SDT agrees and has revised the standard to clarify that recording is the responsibility of the entity that owns the equipment.		
DTE Energy/Detroit Edison	No	Recommend that generator low side breaker monitoring should be excluded or optional if the high side breaker connected to the system is monitored.
Response: Thank you for your comments. The intent of monitoring generator circuit breakers is to determine when a generator is connected to the grid. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the high side circuit breaker that connects the GSU to the grid, the SDT believes it is reasonable to require monitoring of both circuit breakers.		
Wisconsin Electric	No	In R2, the Generator Owner is required to record Sequence of Events (SER) data for circuit breaker status for the equipment in the substation connected to a generating station of a specified capacity, in addition to that for the GSU. This appears to be an unnecessary duplication of equipment already being monitored by the Transmission Owner in R1. If this is a correct interpretation, we believe this requirement is redundant, and technically and financially unjustified. We strongly oppose requiring duplication of monitoring equipment for the same facility by both Transmission Owners and Generator Owners.
Response: Thank you for your comments. The standard has been reworded to require the owner of the circuit breaker to do the monitoring of the circuit breaker status.		
City of Tallahassee (TAL)	No	R1.1 is unclear. Is it the intent of the SDT to exclude substations with 3 or more lines at 200kV or above if there is no transformation at that substation? That appears to be what is required based on the "and" statement. R1.2: Some confusion may be encountered when determining if it is a "plant" or "site" aggregate. Some utilities may not use the same nomenclature for each item. Two 900MW plants (or units) at one site should be captured, even though they are not a plant aggregate of 1500MVA.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The proposed standard refers to individual generators of 500 MVA with a combined generation at site of 1500 MVA. The generation size requirements have been changed.		
NV Energy (fka Sierra Pacific Resources)	No	The requirement to provide Sequence of Events recording data for stations with three or more transmission lines operated at 200kV or above seems to be overly burdensome. This requirement if left as written would potentially include a significant number of remote substations. As an alternative, we suggest that this requirement be changed to "stations with five or more lines operated at 200kV or above".
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Salt River Project	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. Suggest that this requirment be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Progress Energy Carolina, Inc.	No	Table 2-1 indicates "Including low side breakers" for plant SER data inputs. If an aggregate generation site of 1500MVA is monitored at the >200kV level where the generation enters the transmission network, the system impact of any occurrence will be seen at the monitoring point. PEC dissagrees with the low side breakers position being included to be monitored by the DFR/SER. Monitoring of these breakers are included within the functional boundaries of the smaller generating units and the breaker voltages are less than 50KV and not part of the transmission grid. Extending this requirement will be costly since the DFR will be located at the transmission network location remote to the multiple generators and low side breakers. The requirement should only include the >200kV circuit breaker SER data.
Response: Thank you for your comments. The intent of monitoring generator circuit breakers is to determine when a generator is connected to the grid. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the high side circuit breaker that connects the GSU to the grid, the SDT believes		

Organization	Yes or No	Question 7 Comment
it is reasonable to require monitoring of both circuit breakers.		
Hydro-Québec TransEnergie (HQT)	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions, protective relay tripping for all protection groups, and teleprotection keying and receiving.
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis.		
Brazos Electric Power Cooperative, Inc.	No	Need to add clarity to the criteria and do not reference Tables for requirements.
Response: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Northeast Utilities	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions and protective relay tripping for all protection groups.
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information such as protective relay tripping could provide further insight in the event analysis.		
San Diego Gas and Electric Co.	No	The requirement for collecting SOE data at subs with three or more transmission lines operated at 200kV or above seems a bit stringent for the value received. We would suggest this requirement be put in place for substations with five or more lines operated at 200kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
New York Independent System Operator	No	The Loss of generation affects the entire system regardless of interconnection voltage, and just knowing when breakers trip doesn't add enough information. In addition to circuit breaker position change, SOE data should be available for generator protective functions to enable the GO to report the root cause of generator trips which occur due to system disturbances. This is to support possible future blackout investigations and eventually lead to betters standards for generator transmission system coordination. It is very important to capture root cause for units/plants of significant size, and this need is not dependent on interconnection voltage. Change SOE requirement for single unit to 50MVA+, and Plant to 300MVA+. Require SOE to monitor CB positions, protective relay tripping for all protection groups and teleprotection keying and receiving.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis. The generation size requirements have been changed.		
E.ON U.S.	No	The requirements seem to go beyond what is needed for bulk power system reliability. The requirements appear to prescribe equipment and processes so as to establish conventions that would enable the utility's response to broad operating data requests.
Response: Thank you for your comments. The intent of the standard is to provide information to analyze system disturbances.		
Arizona Public Service Co.	No	Requiring sequence of events data for all substations 200 kV and above with 3 or more lines is too stringent. It will provide more data but drowning in data isn't the goal. This should be relaxed to substations with 5 or more lines as these will eliminate the smaller less important substations.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Tucson Electric Power	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
CenterPoint Energy	No	CenterPoint Energy disagrees including the proposed sequence of events (SOE) requirements. SOE data is proposed for every change in circuit breaker position (open/close) for EACH circuit breaker in a substation operated at 200kV and above. Such SOE requirements are actually related to SCADA (supervisory control and data acquisition) equipment, not fault and disturbance recording equipment. Such requirements would essentially dictate the specification and the installation, or replacement, of SCADA sets and logic cages. CenterPoint Energy recommends removing SOE requirements from PRC-002. Should the industry determine SOE requirements belong in this standard, CenterPoint Energy recommends SOE recording only be required wherever Fault Recording Data is required. It is present industry practice that Fault Recording Data devices incorporate SOE capability and that SOE data include such information as protective relay pick-up time, as well

Organization	Yes or No	Question 7 Comment
		as breaker interrupting / operating time.
Response: Thank you for your comments. While fault recorder data only may be sufficient for the analysis of most events, during major disturbances more detailed sequence of events information is required. The standard has been written to describe what quantities are needed, not what type of equipment is required to do the monitoring. Using a DFR to record SOE data is acceptable if it meets the timing and time synchronization requirements.		
Xcel Energy	No	R2 is written such that it appears that the Generator Owner will have to duplicate the SOE recording assigned to the Transmission Owner in R1.2. We assume that was not the SDT's intent, so we recommend that the third and fourth lines of Table 2-1 be modified to read "Each circuit breaker 200 kV and above if not already monitored by the Transmission Owner."
Response: Thank you for your comments. The standard has been revised to require the owner of the circuit breaker to monitor the status.		
Utility System Efficiencies, Inc.	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems overly burdensome. This requirement would potentially include a significant number of remote substations. I suggest that this requirement be for substations with five or more lines operated at voltages between 200 kV and 300 kV and for substations with three or more lines operated at voltages over 300 kV.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
British Columbia Transmission Corporation	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. I suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA		

Organization	Yes or No	Question 7 Comment
criteria. This is included in the revised draft standard.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response: Thank you for your comments. Please see the response to the comments of the IRC Standards Review Committee.		
Tri-State Generation and Transmission Association	Yes	We would like to ensure that no separate Sequence of Events Recorder is required if the data can retrieved from archived SCADA logs.
Response: Thank you for your comments. If SCADA logs meet the timing requirements as stated in the standard – and many do – SCADA can be used for sequence of events.		
Dominion	Yes	The location requirements for SOEs and FRs for TO should be the same. If we use a table under R4 then use a similar table under R1- R2 remove its and replace with Generator Owner, and re-label Heading of Table 2-1 to indicate: for generating plant and substation equipment owned by Generator Owner? Table 2-1 - remove the third and fourth row of info. Move the "each circuit breaker 200 KV and above" in the right hand column of rows 3 and 4 to right hand column of rows 1 and 2.
Response: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
American Electric Power	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NV Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Cowlitz County PUD	Yes	
Schneider Electric	Yes	

Organization	Yes or No	Question 7 Comment
PHI (PEPCO Holdings Inc.)	Yes	
Entergy Services, Inc	Yes	
Florida Power & Light	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
Kansas City Power & Light	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Independent Electricity System Operator	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Manitoba Hydro	Yes	
Grant County PUD	Yes	
ITC Transmission, METC	Yes	
FirstEnergy	Yes	
SPP System Protection and Control Working Group	Yes	
Pacific Northwest National Laboratory		

Organization	Yes or No	Question 7 Comment
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
WECC		

Requirements related to Fault Recording

8. Requirement R6 states that Fault Recording data shall include a pre trigger record length of at least two cycles and: a post trigger length of at least 50 cycles, or the first three cycles and the final cycle of an event. Do you agree with the requirement? If not, please propose alternate values or requirements and provide rationale.

Summary Consideration: While a majority of commenters supported these pre trigger and post trigger lengths, there were some requests for clarification, which the standard drafting team has addressed. Other commenters requested a definition for an event and asked what determines the final cycle of the event.

The drafting team undertook a significant rewriting of the draft standard. The requirement language was modified for clarity and the term “event” was removed. To determine location criteria, a task team was formed to develop a technical basis for the requirements; that basis is included in the revised draft standard.

Organization	Yes or No	Question 8 Comment
IRC Standards Review Committee	No	The SRC questions the need for two seemingly divergent Methods to achieve the reliability data objective. If the objective is to ensure that 2 cycles of pre-event data is available (to establish a base line) then both methods do that. But then Method 1 stores 50 cycles of data and ends (in essence losing all information after that 50

Organization	Yes or No	Question 8 Comment
		cycles). The second Method saves 3 cycles of post-event data and 2 cycles of data at the end. That means for events lasting longer than 50 cycles Method 1 is missing the end of event information, and Method 2 may not have any data at all after the first two cycles (except for the 3 cycles at the very end of the event). The SRC would ask what is the information that is needed for analysis. Seemingly these two methods are saving different pieces of data and yet both are acceptable. What is the technical basis for the 16 samples per cycle requirement? The SRC would also suggest that Requirement 6 be separated into two independent requirements - one for TOs and one for GOs. Although the intent to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R4 and R5 criteria.
Response: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate. The value of 16 samples was chosen because all but the oldest microprocessor based relays sample at this rate or higher. The standard has been revised to clarify TO and GO requirements.		
SPP System Protection and Control Working Group	No	Recommend to change "first three cycles" to "first six cycles". Six cycles will give you the relay time plus the breaker time.
Response: Thank you for your comments. The SDT received strong support in the first posting for the requirement as written. No change made in that respect.		
SERC Engineering Committee Planning Standards Subcommittee	No	It is not clear why there are two different requirements for sampling data.
Response: Thank you for your comments. If you are referring to the differences in the sampling rates for fault records and DDRs, the differences are related to the data requirement differences between those two types of events.		
MRO NERC Standards Review Subcommittee	No	The first three cycles of an event and the final cycle of an event doesn't seem adequate.
Response: Thank you for your comments. On a large interconnected system, most faults will be recorded by multiple devices, including devices capable of recording longer records. The SDT believes that adequate information will be recorded and these fault record lengths have been selected to allow for legacy equipment.		

Organization	Yes or No	Question 8 Comment
NERC	No	The term "final cycle of the event" is confusing. The recording should remain for at least 2 seconds or until the triggered value has been eliminated.
Response: Thank you for your comments. The "final cycle of an event" requirement was intended to determine when a fault cleared, and "an event" has been changed to "the fault.". The final cycle of an event is the last electrical cycle that fault current was flowing. Requiring a two-second record length, or requiring the installation of a device that will continuously record until a fault clears, will eliminate the use of all but the latest generation of microprocessor based relays, and most legacy DFRs. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate. In addition, the newer equipment installed at locations that previous had no equipment will have that capability, and are likely to record events one or more substations away, and that data will help in event analysis.		
Progress Energy Florida	No	Wording is not very clear as to the fault length. An example on how it could be worded would be: "Recording duration shall be at least 50 cycles in total length with a minimum of 2 cycles of pre-fault data (or pre trigger)".
Response: Thank you for your comments. The standard drafting team thinks that the requirement as worded makes clear that the minimum number of cycles is 52: 50 cycles post-trigger and a pre-trigger record length of two cycles.		
Independent Electricity System Operator	No	We do not see the two sets of condition to cover the same period or achieve the same objective. The first condition requires recording that covers a (continuous) period from -2 cycles to +50 cycles of a trigger.In the second condition, the periods covered appear to be (a) -2 cycles to +3 cycles of a trigger, and (b) the last 3 cycles of the "event". Our questions and comments are: i. Are "trigger" and "event" interchangeable? If so, what does R6 mean by "the last cycle of the event" given that there is already a requirement for the +3 cycles of the trigger ii. If they are not interchangeable, what does it mean by an "event" iii. The two conditions appear to require recording different time periods since in the second condition, the recording is not continuous from -2 cycles to +50 cycles of the trigger; as written, it only covers a period of -2 cycles to +3 cycles, then a void until the last cycle of the "event", which is not defined. If however the intent is to record the event 2 cycles before it occurs through to the end of the event, which is hard to define, then we suggest the second bullet be revised as follows: A pre-trigger record length of at least two cycles and a post-trigger record length that extends up until the trigger condition no longer exists. Still we are unable to rationalize how the "first 3 cycles of the event" fit in.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. The standard drafting teams does not think that “trigger” and “event” are interchangeable. Since this requirement is related to fault recording, the event is a fault that occurred. The trigger is a setting in the recording device that causes the device to record the event. The intent of this wording was to be able to determine when a fault started, and when it ended, while allowing legacy microprocessor based relays and legacy DFRs to be used to meet the standard. On a large interconnected system, most faults will be recorded by multiple devices, including devices capable of recording longer records. If the fault lasts for more than 50 cycles, there will likely be multiple records initiated by a DFR, and very likely a microprocessor based relay that clears the fault.		
City of Tallahassee (TAL)	No	I do not have the expertise to respond to the trigger lengths. However, R6.1 bullet 2, What is an "event"? Is this different from the Disturbance used in R13?
Response: Thank you for your comments. Since this requirement is related to fault recording, the event is a short circuit that occurred. The trigger is a setting in the recording device that causes the device to record the event. The term “Disturbance” used in Requirement R13 of draft 2 of the standard is the NERC Glossary term.		
Progress Energy Carolina, Inc.	No	Ok with first bullet under R6.1, however, the second bullet refers to "event" without a definition of what constitutes an "event".
Response: Thank you for your comments. The term “event” has been removed from the draft standard.		
New York Independent System Operator	No	There is confusion over the meaning to the second option. Does it mean for faults with a duration of greater than 50 cycles this is the minimum record? Or does this allow for use of relays with limited fault recording to be used? Regardless, this record is not equal to the first option. The second record option would be inadequate.
Response: Thank you for your comments. You are correct in the assumption that the second option was added to allow the use of legacy microprocessor based relays and legacy DFRs. With time stamping added, legacy equipment that meets the draft standard’s (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
E.ON U.S.	No	Generally, pre-trip data has more analytical value than post-trip data.
Response: Thank you for your comments. The standard does not address trip data, rather data gathered for a triggered event. The value of pre-trigger data versus post-trigger data depends on what you are trying to analyze. The standard does not preclude anyone from recording additional pre or post trigger data.		
JEA	No	Various manufacturer's equipment does not presently support this requirement. Special designs and modifications to certain types of relays and fault recording equipment will need to be developed to fully support

Organization	Yes or No	Question 8 Comment
		this requirement, as presently written.
Response: Thank you for your comments. The requirements were drafted to allow for the use of as many legacy recording devices as possible while still providing adequate information to analyze faults.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments to this question. The AESO would also suggest that the R6 could be revised to require post trigger recording to be "at least 50 cycles post trigger AND the last cycle for extended faults".
Response: Thank you for your comments. See our response to the IRC SRC. Requiring at least 50 cycles would prevent the use of most protective relays which have proven adequate for most events. In the rare event that a fault lasts more than 50 cycles, it is likely that other protective relays and other DFRs will also record the fault.		
Beckwith Electric Co	No	This section needs to be rewritten. It is confusing the way it is written with two different options. There is no definition of triggering. As an example: if the triggering is achieved using an input contact (generator/GSU breaker 'a' or 'b' contact) then having 2 cycle pre-tiggering will not capture the required important information and will have 50 cycles of post trigger data which is useless as the breaker has already opened. The other problem is that unlike transmission line relay operations (typically happens much shorter than 50 cycles) the generator relay operations can take several seconds from the inception of fault/abnormal condition (example: loss of field, under frequency, V/Hz, out of step, reverse power etc). Recommend changing the total record length to at least 5 sec with pre and post trigger length selectable based on the triggering mechanism.
Response: Thank you for your comments. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did; however, add a requirement that requires TOs and GOs to have a triggering methodology. The drafting team feels that this requirement does not prescribe what to trigger for, but rather makes sure that the responsible entities have an established methodology to trigger for events. Once the generator is islanded from the transmission system within the time frame specified, the intent of the standard is to capture wide area events. The generator scenario provided does not have a wide area impact. The standard states that: "A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles for the same trigger point OR at least two cycles of the pre trigger data; the first three cycles of the fault; and the final cycle of the fault." An entity is able to record a longer data length as long as it meets the requirement above.		
Kansas City Power & Light	No	Do not agree with the notion of data recording of the first 3 cycles and the final cycle. The first three cycles and the last cycle is not sufficient data to be useful for fault recording analysis. At least 6 cycles is needed at the beginning of the record. Although 6 cycles is better, that still does not guarantee sufficient data will be collected

Organization	Yes or No	Question 8 Comment
		in every instance. Recommend the SDT consider changing to capturing 6 cycles.
Response: Thank you for your comments. The SDT feels that this is a sufficient for recording most events.		
Northeast Power Coordinating Council	Yes	This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
Response: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
Members of the WECC Disturbance Monitoring Work Group	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Southern Company - Transmission	Yes	No further comment.
Response: Thank you.		
SERC Protection and Controls Sub-committee	Yes	Add to the end of the first bullet for the same trigger point?
Response: Thank you for your comments. The standard has been revised to include your suggestion.		
Dominion	Yes	Add to end of first bullet under R6.1 "for the same trigger point"
Response: Thank you for your comments. The standard has been revised to include your suggestion.		
Bonneville Power Administration	Yes	The number of element criteria may be too stringent, change to 5 elements.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit		

Organization	Yes or No	Question 8 Comment
MVA criteria. This is included in the revised draft standard.		
Florida Power & Light	Yes	We agree, however, the term "event" needs to be defined. Please provide a working definition for event.
Response: Thank you for your comments. The term "event" has been removed from the draft standard.		
PG&E System Protection	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"? We recommend that we use "end of the event" instead.
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
NYISO	Yes	Yes, this sounds good, but we don't understand how one could record the first 3 cycles and final cycle of an event.
Response: Thank you for your comments. This can be done in microprocessor based relays by recording two or more records and by using appropriate triggers.		
Tri-State Generation and Transmission Association	Yes	How is the final cycle of an event determined?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing.		
Cowlitz County PUD	Yes	If the former requirement is preferred, would it be best to require all new equipment abide by the 2 - 50 cycle requirement and only allow the first three cycles and the final cycle method for existing legacy equipment? I would not take issue with this when the standard is up for a vote.
Response: Thank you for your comments. It is likely that new protective relays will be able to record the longer records, but the SDT did not want to prescribe in the standard that all new protective relay schemes use the latest available protective relays.		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle		

Organization	Yes or No	Question 8 Comment
that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Puget Sound Energy	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
NV Energy (fka Sierra Pacific Resources)	Yes	The Standard is unclear in the use of the terminology "final cycle of an event". Can this be further defined for clarity of the Standard?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Salt River Project	Yes	What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Hydro-Québec TransEnergie (HQT)	Yes	This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
Response: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
Northeast Utilities	Yes	This requirement allows for the inclusion of legacy equipment. However, this requirement does not stipulate the recording of adequate information for analysis of events that are more complex than a simple fault-trip.
Response: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
San Diego Gas and Electric Co.	Yes	Is there a definition of "the final cycle of an event"? We'd want to make sure that we understand that fully.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Arizona Public Service Co.	Yes	If you tell me what the definition of the end of an event is and then I'll be sure to capture the "final cycle" of the event.
Response: Thank you for your comments. The term "event" refers to a fault (e.g. short circuit) recorded by a fault recorder. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Tucson Electric Power	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Utility System Efficiencies, Inc.	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
British Columbia Transmission Corporation	Yes	What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
US Bureau of Reclamation	Yes	
Exelon Generation LLC	Yes	
Entergy Services, Inc	Yes	
PHI (PEPCO Holdings Inc.)	Yes	

Organization	Yes or No	Question 8 Comment
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
ITC Transmission, METC	Yes	
NV Energy	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	
American Electric Power	Yes	
Schneider Electric	Yes	
Duke Energy	Yes	
Grant County PUD	Yes	
Wisconsin Electric	Yes	
PNM	Yes	
PacifiCorp	Yes	
Pacific Northwest National Laboratory		
WECC		
Brazos Electric Power Cooperative, Inc.		

Organization	Yes or No	Question 8 Comment
National Grid		
DTE Energy/Detroit Edison		
TransAlta		
Los Angeles Department of Water & Power		
CenterPoint Energy		

Requirements related to Fault Recording

9. Do you agree with the other Fault Recording requirements in R4 through R6 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration: Comments indicated that the majority of respondents disagreed with Fault Recording requirements under R4 through R6. Commenters suggested increasing the number of lines criteria to a quantity of five or greater. Additionally, commenters pointed out that FR triggering requirements are not addressed.

To address these concerns, the drafting team undertook a significant rewriting of the draft standard. The requirement language was made clearer and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received, the task team developed location criteria for SOE and FR data to be 25-percent of bus locations with the highest calculated short circuit MVA level.

After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. The drafting team did, however, add a requirement that requires applicable owners to have a triggering methodology. The drafting team feels that this requirement does not prescribe for what to trigger, but rather makes sure that the responsible entities have an established methodology to trigger for events.

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	Referring to Requirement 4.1, the number of phases to be monitored is excessive. It will not provide any analytical benefit. Monitoring every transmission line in a ring bus is excessive. The second bullet referring to a breaker-and-a-half arrangement needs clarification. What is the "outer bus" in that arrangement? Definitions should be provided when references are made to substation designs or equipment that could have different names or designations in the industry. As we commented in Question 5, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. This needs to be reflected in Table 4-1.Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2). Referring to Requirement R5, the comments to R4.1 and R4.2 are applicable. In Table 5-1 the requirements that refer to the high side of critical GSU's should be directed at Transmission Owners, not Generation Owners. Referring to Requirement R6.1, the second bullet does not provide for the recording of adequate information (see response to Question 8).
Response: Thank you for your comments. Monitoring of all three phases is necessary for the analysis of all fault types. Monitoring all three phases, or two phases and the residual, will provide enough data to determine all three phases and the residual. The drafting team will consider developing an FAQ document to clarify		

Organization	Yes or No	Question 9 Comment
voltage monitoring requirements on ring buses and breaker-and-a-half arrangements. The standard is also being revised to more clearly indicate what equipment each GO and TO must monitor. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven adequate.		
IRC Standards Review Committee	No	The SRC agrees with the data itself. The SRC does not agree that each data item listed in R4 must be an independent requirement. The SRC supports compliance with R4, but that the suggested sub-requirements be bullet items and that those items be handled through VSLs. Similarly with R5, the data items should be bulleted rather than being shown as independent. Similarly with R6, the data items should be bulleted rather than being shown as independent.
Response: Thank you for your comments. They were not intended to be interpreted as independent requirements; the SDT undertook a significant rewriting of the draft standard to provide clarification.		
Members of the WECC Disturbance Monitoring Work Group	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Bonneville Power Administration	No	BPA does not believe the individual phase voltage of each line is required if Bus voltage at the station is recorded. We think the R4.1 may say that, but maybe change the wording order to "The three phase to neutral voltages on each main bus or monitored line as follows:", It shouldn't be required to monitor the voltages on a transfer bus in a main and auxiliary (transfer) bus scheme. The number of element criteria may be too stringent, change to 5 elements.
Response: Thank you for your comments. The recording of every line and bus voltage is not explicitly stated. What is stated is that the voltages must be able to be determined. As long as an adequate number of voltages are recorded, such as every other bus or line on a ring bus, and circuit breaker position is known, all voltages can be determined. How an individual company chooses to comply with the requirements may vary from one GO or TO to the next. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		

Organization	Yes or No	Question 9 Comment
PG&E System Protection	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NERC	No	R4.1 It is important for forensic analysis to have both bus and line quantities for DFR quantities. Bullets 2 and 3 should read: On breaker-and-a-half arrangements, the outer bus voltages, and the individual line voltages. On straight buses, common bus voltages and the individual line voltages.
Response: Thank you for your comments. There are multiple ways to determine every line and every bus voltage. If the two sets of bus voltages in a breaker-and-a-half scheme are recorded, and the status of every circuit breaker is known, all bus and line voltages can be determined.		
NYISO	No	R4.1 requires monitoring of 3 phase voltages on all bus sections of ring buses. We believe this is excessive. Reduce requirements to enough to be able derive all the quantities during normal maintenance conditions (outages).R5.5, second row in table: This puts the responsibility to monitor a transmission substation on the generator owner. Change the requirement such that the substation owner needs to monitor this.
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. The SDT has revised the standard to more clearly differentiate GO and TO monitoring requirements.		
Tri-State Generation and Transmission Association	No	The R4.1 and R5.4 ring bus requirements to monitor three-phase voltages on each transmission line seems unnecessary for reliability or for post-event analysis. Voltages from opposite locations on a ring bus should ensure that sufficient quantities are available to perform any required calculations.
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually.		
Portland General Electric	No	The following comments are those filed by the DMWG which we are filing in support: Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Progress Energy Florida	No	Monitoring of GSU transformer currents on units >500MVA is the correct approach. However, peaking generation locations will have many generating units of less than 500MVA. The aggregate combination of 1500MVA will encompass many GSU transformers. Monitoring of each of the GSUs' currents (even though they are >200kV) will require extensive DME equipment additions at locations remote to the transmission network where the DME equipment is (and should be) located. We believe these total aggregate generation currents should be monitored at the location where they are introduced to the transmission network. This location may be at an exit point from a generating unit bus or a transmission line the feeds the generation power into another remote transmission substation bus.
Response: Thank you for your comments. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection since this will be the same as the total plant output.		
Puget Sound Energy	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Independent Electricity System Operator	No	Please see our comments on R6, above.
Response: Thank you. See our response to R6 above.		
NextEra Energy Resources (formerly FPL Energy)	No	Section R4.1Recommend changing the first bullet to read On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages. Section R4.2Recommend removing the word transformer from the qualifying sentence and changing the wording to The three phase currents and the residual or neutral currents of each monitored element as noted in Table 4-1. Table 4-1Recommend changing the single generating unit level to 750MVA or higher to avoid unnecessary

Organization	Yes or No	Question 9 Comment
		Fault Recording Equipment installations Section R5.1Recommend removal of language restricting the location of where to monitor for three phase to neutral voltages or phase to phase voltages associated with the GSU. Statement should allow for monitoring at T-line level as well. Section R5.2Recommend removal of language restricting the location of where to monitor for three phase to neutral voltages or phase to phase voltages associated with the GSU. Statement should allow for monitoring at T-line level as well. Section R5.4Recommend changing the first bullet to read On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages. Section R5.5Recommend removing the word transformer from the qualifying sentence and changing the wording to The three phase currents and the residual or neutral currents of each monitored element as noted in Table 4-1. Table 5-1Recommend changing the single generating unit level to 750MVA or higher to avoid unnecessary Fault Recording Equipment installations.
Response: Thank you for your comments. Your recommendation for voltage locations to be monitored has been incorporated into the latest revision of the standard. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The standard is specifically worded to allow recording of voltages and currents on either side of a GSU. The SDT doesn't agree with your recommendation about changing the single generating unit level to 750MVA, thus the single generator nameplate rating remains at 500 MVA or above.		
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirement R5.4: Requirements identified in this section for monitoring bus and line voltages belong to TO and not to GO unless GO owns the Substation. The revision should clearly state that.2. Requirement R5.4: We heard during the Q&A session of the webinar on 3/12/09 that GSU neutral current can be recorded by the residual current (sum of three phase currents). The revision should clearly state that. 3. Requirement R5.4: Please clarify that recording of Generator Step Up transformer (GSU) phase currents can be done by deriving these currents from the GSU output breaker(s) currents. The revision should be modified to state this and that the GSU neutral current can be recorded by deriving this current from the GSU output breaker(s) phase

Organization	Yes or No	Question 9 Comment
		currents. (Most of our GSUs are connected to the switchyard thru two output breakers in a ring bus. It makes lot more sense from a schedule and cost view point to use the quantities from the CTs of these output breakers rather than from the GSU CTs. It also makes sense from reliability viewpoint as less cabling means more reliability for the equipment, especially when with less additional cabling/wiring; we are recording the required quantities.) 4. Requirement R5.5: Requirements identified in this section for monitoring line three phase currents and the residual and monitored current belong to TO and not GO unless GO owns the Substation. The revision should clearly state that.
Response: Thank you for your comments. 1) The standard is being revised to clearly indicate what equipment each GO and TO should monitor. 2 and 3) If your GSU is delta on the low side and wye on the high side, the GSU neutral current cannot be determined by summing the three phase currents on the low side. The neutral current can be determined by summing the three phase currents on the high side. The intention of the standard is to tell each GO and TO what quantities are needed, not how to record them, since each entity may use a different approach that suits their needs. 4) The standard has been modified to explicitly state what equipment a GO and TO is to monitor.		
DTE Energy/Detroit Edison	No	Consider change to allow high side GSU voltage to be monitored at the high side bus of the same voltage. Present wording can be taken to imply that voltage must be monitored directly at GSU high side terminals. Also, can parallel GSUs be allowed to be monitored at a common point rather than individually? Likewise, can two GSUs connected at a common point at 200 kV or above be allowed to be monitored together at the common connection point?
Response: Thank you for your comments. The standard has been modified to indicate that either high or low side voltages and current can be recorded. The standard has been revised so that parallel GSUs can be monitored at a common point or individually. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection, since this will be the same as the total plant output.		
Wisconsin Electric	No	In R5.4 and R5.5, the Generator Owner is required to record Fault Recording data for equipment in the substation connected to a generating station of a specified capacity, in addition to that for the GSU. This appears to be an unnecessary duplication of equipment already being monitored by the Transmission Owner in R4. If this is a correct interpretation, we believe this requirement is redundant, and technically and financially unjustified. We strongly oppose requiring duplication of monitoring equipment for the same facility by both Transmission Owners and Generator Owners. Also, In R5.2, the statement is given that the three-phase current data from the "generator bus" is sufficient for monitoring. Does this mean that the three-phase currents from generator current transformers will meet this

Organization	Yes or No	Question 9 Comment
		requirement?
Response: Thank you for your comments. The standard is being revised to clearly state that a GO is to monitor equipment that the GO owns, and the TO is to monitor the equipment the TO owns. Yes, this is the intent of Requirement 5.2.		
City of Tallahassee (TAL)	No	R4.1, Bullet #1 appears too restrictive for a ring bus. It will require a fault recorder on each bus section with a line going to it. This is also a potential conflict with R7, which allows a recorder up to 2 busses away.Table 4-1. Am I correct in assuming that if there is no transformation with both sides >200kV, I do not need recording no matter how many lines are there. Same concern with "plant" vs. "site".
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. R7 is only for dynamic disturbance recording, not for fault recording, so there is no conflict. Your assumption is incorrect regarding transformation and number of lines. The standard does not address sites but rather Transmission switching stations, transmission substations, generating stations, HVAC converter stations, HVDC converter stations.		
NV Energy (fka Sierra Pacific Resources)	No	Table 4-1 should also be modified to identify Substations containing any combination of five or more elements. See response to Q7 previous.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Salt River Project	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Progress Energy Carolina, Inc.	No	Monitoring of GSU transformer currents on units >500MVA is the correct approach. However peaking

Organization	Yes or No	Question 9 Comment
		generation locations will have many generating units of less than 500MVA. The aggregate combination of 1500MVA will encompass many GSU transformers. Monitoring of each of the GSUs' currents (even though they are >200kV) will require extensive DME equipment additions at locations remote to the transmission network where the DME equipment is (and should be) located. We believe these total aggregate generation currents should be monitored at the location where they are introduced to the transmission network. This location may be at an exit point from a generating unit bus or a transmission line the feeds the generation power into another remote transmission substation bus.
Response: Thank you for your comments. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection, since this will be the same as the total plant output.		
Hydro-Québec TransEnergie (HQT)	No	Referring to Requirement 4.1, the number of phases to be monitored is excessive. It will not provide any analytical benefit. Monitoring every transmission line in a ring bus is excessive. The second bullet referring to a breaker-and-a-half arrangement needs clarification. What is the "outer bus" in that arrangement? Definitions should be provided when references are made to substation designs or equipment that could have different names or designations in the industry. As we commented in Question 5, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. This needs to be reflected in Table 4-1.Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2). Referring to Requirement R5, the comments to R4.1 and R4.2 are applicable. In Table 5-1 the requirements that refer to the high side of critical GSU's should be directed at Transmission Owners, not Generation Owners. Referring to Requirement R6.1, the second bullet does not provide for the recording of adequate information (see response to Question 8).
Response: Thank you for your comments. Monitoring of all three phases is necessary for the analysis of all fault types. Monitoring all three phases, or two phases and the residual, will provide enough data to determine all three phases and the residual. The drafting team will consider developing an FAQ document to clarify voltage monitoring requirements on ring buses and breaker-and-a-half arrangements. The standard is also being revised to more clearly indicate what equipment each GO and TO must monitor. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven adequate.		
Brazos Electric Power Cooperative, Inc.	No	Clarify criteria and remove Tables.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Entergy Services, Inc	No	R4.1 should include provisions to exclude 3 phase potential monitoring for line/bus elements employing line protection schemes, such as current differential relaying, where 3 phase potentials are not presently available and would not needed but for the requirements. Adjacent or remote end element monitoring should be allowable for these cases.
Response: Thank you for your comments. Adequate fault recording requires monitoring of both voltage and current. As long as those voltages can be determined in some manner, the requirements can be met without installing monitoring on every CCVT or VT. Table 4-1 within the draft standard allows for monitoring at remote terminals.		
Northeast Utilities	No	Referring to Requirement 4.1 and 5.4, monitoring the voltage every transmission line in a ring bus is excessive. Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2).
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. Transformer neutral currents do not necessarily need to be monitored if they can be derived from the three phase currents. Neutral currents are frequently desirable for the analysis of ground faults.		
New York Independent System Operator	No	(R4.1) Requiring monitoring 3 phase voltages of all ring bus bus sections is excessive. Reduce requirements to enough to be able derive all the quantities during normal maintenance conditions. (R5.5, second row of table) This puts the responsibility to monitor a transmission substation on the genertator owner. The gen owner likely does not own the transmission substation. Make monitoring this equipment the responsibility or the transmission owner.(following R6.) We note that there is no mention of FR triggering. While this is specific to the various manufacturers trigger algorithms and specific also to the location, there does need to be a statement that the FR is to trigger for near-by faults, system disturbances, and relay operations. While this type of consideration is difficult to address in a standard, it would be misleading to leave out entirely a statement that reliable FR triggering is necessary. We request that the team add a new provision stating that all required FR channels at a location should be recorded whenever a trigger asserts on any one of them.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to derive all voltages without recording every line or bus individually. The SDT is revising the standard to clearly state that the owner of the equipment is to do the monitoring. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did, however, add a requirement that the applicable owner have a triggering methodology. The drafting team believes that this requirement does not prescribe what to trigger, for but rather makes sure that the responsible entities have an established methodology to trigger for events.		
Tucson Electric Power	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. As stated above to the IRC SRC, they were not intended to be interpreted as independent requirements. The SDT undertook a significant rewriting of the draft standard to provide clarification.		
CenterPoint Energy	No	The requirements to record all three phase to neutral voltages and all four currents on each transmission line are prescriptive and excessive. The monitoring of two sets of line voltages, in all substation configurations, is a common industry practice which has met the industry's needs. It is unnecessary and excessive to require monitoring of more than two sets of three phase to neutral voltages in any substation arrangement.
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually.		
Xcel Energy	No	As with Question 7, R5 is written such that it appears that the Generator Owner will have to duplicate the fault recording assigned to the Transmission Owner in R4. We assume that was not the SDT's intent, so we recommend that the second line of Table 5-1 include a clarifying statement such as "if not already monitored by

Organization	Yes or No	Question 9 Comment
		the Transmission Owner."
Response: Thank you for your comments. See answer to question 7 above. Additionally, the standard has been revised to clearly what equipment each GO and TO should monitor.		
Utility System Efficiencies, Inc.	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements operated between 200 kV and 300 kV and for substations with three or more elements operated at voltages over 300 kV. See my response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
British Columbia Transmission Corporation	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Kansas City Power & Light	No	It is not necessary to require voltages on every line and bus for a ring bus configuration. Suggest requiring at least 33% with a of lines or busses for a ring bus configuration and no less than 2 will be a reasonable assurance there is a voltage collection for fault recording for events. It is unlikely under normal conditions 33% of the lines or busses in a ring would be out of service concurrently. So, for ring configuration stations with up to 6 lines, 2 voltage measures would be required. Ring configuration stations between 7 and 9 lines would require 3 voltage measures. Ring configuration stations with 10 to 12 lines, 4 voltage measures would be required. And so on.
Response: Thank you for your comments. The recording of every line and bus voltage is not explicitly stated in the standard. What is stated is that the voltages must be able to be determined. As long as an adequate number of voltages are recorded, such as every other bus or line on a ring bus, and circuit breaker position is known, all voltages can be determined.		
PNM	No	R5.3 requires recording current at the neutral bushing of wye-connected GSU transformer high-side windings. That does not have enough value to be a requirement. With the defined time synch. requirements and abundance of recorded voltages correlation of values is accomplished. It may have some value where only

Organization	Yes or No	Question 9 Comment
		low-side generator currents are monitored but not where high-side GSU currents are monitored.
Response: Thank you for your comments. The standard states that these values may be determined, not necessarily monitored. As written, the high side neutral current is only required if low side phase currents are recorded instead of the high side phase currents.		
Dominion	Yes	Re-label heading of table 4-1 to indicate:" for substation equipment owned by Transmission Owner"
Response: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
MRO NERC Standards Review Subcommittee	Yes	Table 5-1 has a type-o - Row 2, Column 2, bullet 1 extra 'd'.
Response: Thank you. This has been corrected.		
PHI (PEPCO Holdings Inc.)	Yes	FR trigering requirements are not addressed.
Response: Thank you for your comments. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did, however, add a requirement that requires the applicable owner to have a triggering methodology. The drafting team feels that this requirement does not prescribe what to trigger for, but rather makes sure that the responsible entities have an established methodology to trigger for events.		
San Diego Gas and Electric Co.	Yes	Agree, except for the comment made in question 7 above about changing the SOE criteria from three lines to five lines.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
E.ON U.S.	Yes	The SDT should explain the applicability of this requirement to the GO.
Response: Thank you for your comments. The standard has been revised to clearly state what equipment each GO and TO should monitor.		
Arizona Public Service Co.	Yes	There should be a provision for the case if the quantities aren't able to be measured (CT not available for example). In requirement R5.3 it makes the generator owner responsible to record the neutral current of the GSU high voltage winding. Sometimes, generators that have DFRs applied do not have this quantity available

Organization	Yes or No	Question 9 Comment
		as they mostly have access to the low voltage quantities. In addition, if a generator owner has a fault recorder but doesn't have available channels for this additional quantity, he shouldn't be required to drop a channel he feels is important to make room for these mandated channels. For instance, one only needs two voltages and two currents to measure MW so a generator may have fault recording that measures 2 line voltages and 2 line currents and there may not be room to add the additional channels specified. Generally with two of the values you can derive the third so why force them to record all indicated quantities. These requiremens might be acceptable for new generator installations but there are existing installations that would find this ornerous.
Response: Thank you for your comments. The SDT wrote the current recording requirements such that the currents may be determined, not necessarily monitored. It is not possible to derive all three phase quantities and neutral current by recording only two of the four, and the standard was written accordingly.		
SERC Protection and Controls Sub-committee	Yes	Re-label heading of Table 4-1 to indicate: for substation equipment owned by Transmission Owner?
Response: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Southern Company - Transmission	Yes	No further comment.
American Electric Power	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Florida Power & Light	Yes	
Schneider Electric	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 9 Comment
SPP System Protection and Control Working Group	Yes	
Cowlitz County PUD	Yes	
Grant County PUD	Yes	
JEA	Yes	
FirstEnergy	Yes	
US Bureau of Reclamation	Yes	
Pacific Northwest National Laboratory		
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
PacifiCorp		
SERC Engineering Committee Planning Standards Subcommittee		
WECC		

Requirements related to Dynamic Disturbance Recording

10. Requirement R7 states that a DDR which is required at a substation meeting the location requirement shall be considered optional if a DDR meeting all of the requirements of R7.1, R7.2, R7.3 and R7.4 is found to be located one or two substations away. Do you agree with this option found in Requirement R7? If no, provide rationale.

Summary Consideration: In general, commenters agreed that if a DDR is found to be required at a substation and there is one located one or two substations away, the entity is in compliance without needing to install an additional DDR. However, based on industry comments, the SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations, revised every five years.

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light	No	Does R7 require DDR at all substations one station away from the substation meeting the location requirement?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Grant County PUD	No	R7 is very difficult to read. A reword similar to is suggested: When a Transmission owner DOES NOT have Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4, recorded no further than 2 Substations away, then.....
Response: Thank you for your comments. The requirement to establish DDR locations have been revised and reworded.		
CenterPoint Energy	No	CenterPoint Energy disagrees criteria for Dynamic Disturbance Recording (DDR) should be solely based upon the number of connected lines at a substation. In addition to the number of lines, CenterPoint Energy recommends that DDR equipment be required only in substations that have direct interconnections to generating units. By locating DDR capability at generating plants, sufficient DDR data will be available to analyze system disturbances.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		

Organization	Yes or No	Question 10 Comment
IRC Standards Review Committee	Yes	The concept of the requirement is good but the wording can be improved. The issue is how to impose penalties for this requirement. If a TO "can" (i.e. the capability is there) get the required data, but the other TO's DDR fails, then who is responsible for compliance? In short, if each TO is responsible for the data then the two substation caveat has no meaning in cases of different TSOs. In the case of the same TSO it may be useful if the two substation limit is justifiable. The SRC suggests rewriting the requirement in a positive fashion. One example would be: "The Transmission Owner of substations 200KV and above shall have access to Dynamic Disturbance Recording data at or within 2 substations of the subject asset or other processes capable of providing:- R7.1- R7.2- R7.3- R7.4 "This proposal changes the requirement into reporting the required data for events that happen within radius of interest (i.e. two substations).
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Southern Company - Transmission	Yes	Southern Company restates its objection to the use of arbitrary location requirements.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
SERC Protection and Controls Sub-committee	Yes	Refer to response in 5.3
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Bonneville Power Administration	Yes	The DDR's purpose is for wide area monitoring not as a FR device (although it can help with that). Unless it doesn't interface to a control system (HVDC).
Response: Thank you for your comments. The SDT agrees that DDRs are for wide area monitoring. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		

Organization	Yes or No	Question 10 Comment
Florida Power & Light	Yes	This needs to be stated more clearly. Could you provide specific examples as part of FAQs.
Response: Thank you for your comments. The SDT will consider developing an FAQ document.		
Los Angeles Department of Water & Power	Yes	As stated earlier, similar language can be included to exclude transmission lines and substations that are part of a utilities internal distribution system, and not near intertie point.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
NERC	Yes	R7For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1:then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above, the Transmission Owner shall record..."Also, the parenthetical qualifiers in both R7.3 and R7.3 should read:?(for each transmission element operated at 200 kV and above)?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Cowlitz County PUD	Yes	I find the original verbiage of R7 confusing without the clarifying statement above. I would consider rewording R7.
Response: Thank you for your comments. The requirements to establish DDR locations have been revised and reworded.		
American Electric Power	Yes	Repeating DDR across multiple adjacent substations does not add reliability value. Again, clarity is needed to address this requirement in the context of multiple voltage yards within a substation fence.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
City of Tallahassee (TAL)	Yes	See concern in Q9 for R4.1, Bullet 1.
Response: Thank you. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or		

Organization	Yes or No	Question 10 Comment
Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Pacific Northwest National Laboratory	Yes	Yes, but ONLY if the subject substation does not interface to a major control system which cannot be fully monitored from the ac side.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Entergy Services, Inc	Yes	Agree with the criterion of adjacent station coverage consistent with comments on 5.3.
Response: Thank you for your comment. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Utility System Efficiencies, Inc.	Yes	Yes, but ONLY if the subject substation does not interface to a major control system which cannot be fully monitored from the ac side.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
PacifiCorp	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 10 Comment
US Bureau of Reclamation	Yes	
Tri-State Generation and Transmission Association	Yes	
PG&E System Protection	Yes	
Progress Energy Florida	Yes	
NYISO	Yes	
Manitoba Hydro	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Schneider Electric	Yes	
Wisconsin Electric	Yes	
Exelon Generation LLC	Yes	
DTE Energy/Detroit Edison	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 10 Comment
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Carolina, Inc.	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Arizona Public Service Co.	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
JEA	Yes	
Tucson Electric Power	Yes	
Northeast Utilities	Yes	
Duke Energy	Yes	
Xcel Energy	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 10 Comment
SPP System Protection and Control Working Group	Yes	
Northeast Power Coordinating Council	Yes	
British Columbia Transmission Corporation	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
TransAlta		
National Grid		
Puget Sound Energy		
Brazos Electric Power Cooperative, Inc.		
WECC		
E.ON U.S.		

Requirements related to Dynamic Disturbance Recording

11. Requirement R8 states that Generator Owners shall record or have a process in place to derive DDR data for generating plants with an aggregate of 1500 MVA nameplate rating or higher. Do you agree with these values? Please provide supporting documentation for these values or (if you disagree with the values) alternate values and their technical basis.

Summary Consideration: In general, commenters disagreed with the aggregate of 1500 MVA. They supplied a wide range of recommended generator MVA nameplate ratings; The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.

Organization	Yes or No	Question 11 Comment
Hydro-Québec TransEnergie (HQT)	No	a) Referring to Requirement R7, is a Generator Owner required to install a DDR if there is a DDR installed on the plant's outlet transmission system no further than two substations away? b) What is the basis for the "two Substations away" criteria?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Southern Company - Transmission	No	Southern Company disagrees with utilization of arbitrary values to determine placement of disturbance monoritoring equipment. As we have previously stated in our comments, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Northeast Utilities	No	It's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response: The SDT does not agree. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Arizona Public Service Co.	No	If the majority of the 1500 MVA of the plant is recorded, smaller units that are not significant (300 MVA or less) shouldn't be required to be monitored regardless of what voltage level they connect at. Perhaps the requirement could be changed such that if more than 50% of the plant (by MVA) is recorded, units smaller than 300 MVA could be excluded. A generator owner may have a plant that exceeds 1500 MVA when aggregated but this could be due to a few large units, with other smaller units included that are not of consequence.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Northeast Power Coordinating Council	No	a) Referring to Requirement R7, is a Generator Owner required to install a DDR if there is a DDR installed on the plant's outlet transmission system no further than two substations away? b) What is the basis for the "two Substations away" criteria?
Response: The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
IRC Standards Review Committee	No	The SRC agrees with the concept of the requirement .The SRC does not agree that the specified data items should be treated as independent requirements. Further, the SRC suggests that the phrase "physical aggregate" be used.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
DTE Energy/Detroit Edison	No	a) Please see comments for 5.1. b) Also, consideration should be given to applying the "one or two substations away" option to R8 if the entire plant output connects to stations with DDRs.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Wisconsin Electric	No	In R8, the Generator Owner is required to record Dynamic Disturbance Recording (DDR) data for generating stations with a capacity of 1500 MVA or higher. This size requirement is already utilized to require monitoring of Fault Recording data in R5. DDR monitoring is more specialized and should be required at fewer facilities than Fault Recording data. For this reason we believe that the DDR requirement in R8 should only apply at aggregate facilities having a capacity of 2000 MVA or higher.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Members of the WECC Disturbance Monitoring Work Group	Yes	a) The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
PacifiCorp	Yes	We agree regarding the facility rating. However, Generator owners and Transmission owners should be permitted to jointly (by contract) apply a "not more than two bus removed" criteria for siting purposes. In that way duplication can be avoided where there is adequate overlap between generation and tranmission locations. We also support WECC's comments responsive to this question.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Dominion	Yes	Reword R8 to indicate clarify that the 1500 MVA aggregate nameplate rating includes only generation connected at 200 kV (high side of GSU) and above and that any generators at the same facility connected at less than 200 kV are not to be included.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Bonneville Power Administration	Yes	Yes, but BPA does not necessarilly think each GSU needs it. Some GSU's are parralleled onto a single circuit to integrate into the substation. If it's monitored at the substation that should be good.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed value of 1500 MVA would exempt our single unit nuclear generation facilities. We would like to better understand the technical rationale used by the SDT in choosing this value, and the SDT may want to consider lowering this value to 1000 MVA (single) and adding "over 2000 MVA (multiple units)" to assure that the some single-unit nuclear plants will be required to record dynamic disturbances.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
PG&E System Protection	Yes	a) The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		

Organization	Yes or No	Question 11 Comment
Portland General Electric	Yes	a) The following comments are those filed by the DMWG which we are filing in support: The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Puget Sound Energy	Yes	a) The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
City of Tallahassee (TAL)	Yes	Same concern with "plant" vs. "site".
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
NV Energy (fka Sierra Pacific Resources)	Yes	Some clarity is needed with regard to whether the requirement is met if the GO does not own the switchyard, but the data is being recorded by the TO owning the switchyard.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. Data requirements for TOs and GOs are defined explicitly in the revised standard.		
San Diego Gas and Electric Co.	Yes	You might want to address the potential issue of different ownership between the generator and the attached substation, and what that does to the requirements.

Organization	Yes or No	Question 11 Comment
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. Data requirements for TOs and GOs are defined explicitly in the revised standard.		
Tucson Electric Power	Yes	a) The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. b) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Utility System Efficiencies, Inc.	Yes	a) If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, this requirement is not clear whether this situation would meet this requirement. b) Also, what if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
US Bureau of Reclamation	Yes	
MRO NERC Standards Review Subcommittee	Yes	
American Electric Power	Yes	
NYISO	Yes	
Manitoba Hydro	Yes	
Tri-State Generation and Transmission	Yes	

Organization	Yes or No	Question 11 Comment
Association		
Exelon Generation LLC	Yes	
NV Energy	Yes	
Salt River Project	Yes	
Cowlitz County PUD	Yes	
Independent Electricity System Operator	Yes	
NERC	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Schneider Electric	Yes	
Progress Energy Carolina, Inc.	Yes	
Progress Energy Florida	Yes	
Entergy Services, Inc	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
New York Independent System Operator	Yes	

Organization	Yes or No	Question 11 Comment
SERC Protection and Controls Sub-committee	Yes	
British Columbia Transmission Corporation	Yes	
Xcel Energy	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Kansas City Power & Light	Yes	
ITC Transmission, METC	Yes	
SPP System Protection and Control Working Group	Yes	
JEA	Yes	
Los Angeles Department of Water & Power		
Pacific Northwest National Laboratory		
Brazos Electric Power Cooperative, Inc.		
WECC		

Organization	Yes or No	Question 11 Comment
Grant County PUD		
National Grid		
CenterPoint Energy		

Requirements related to Dynamic Disturbance Recording

12. Do you agree with the other Dynamic Disturbance Recorder requirements in R7 through R11 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration: In general, commenters disagreed with the 960 sample per second sampling rate (which currently exists as a requirement in PRC-002-1). A technical analysis was performed on DDR sampling and storage rates, and based on this analysis, the drafting team specified a rate of 960 samples per second as the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The drafting team also realized that there was some confusion about sampling rate and storage rate for calculated values. The wording of the standard has been changed to eliminate this confusion.

Organization	Yes or No	Question 12 Comment
Northeast Power Coordinating Council	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) Referring to Requirement R8, as noted in the response to Question 5 and elsewhere, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications.

Organization	Yes or No	Question 12 Comment
		c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. We have no comment to Requirement R9. d) Our response to Question 2 deals with Requirement R10. e) Requirement R11 should be reworded to: that does not have continuous recording capability shall set its device to trigger and record according to the following where available: Requirement R11.1 should be worded to: R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.

Response: Thank you for your comments.

a) The SDT is accounting for legacy equipment through triggered records, reflected in the updated standard.

b,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.

d) Please see our response to Question 2

e) The SDT revised the triggering requirements (old Requirement R11). The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT recognizes that there are regional variations in the application of triggers and has determined this is a practical approach. The latest revision of the standard allows legacy equipment to be used providing it meets all other requirements. The standard states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.

Organization	Yes or No	Question 12 Comment
IRC Standards Review Committee	No	a) The SRC agrees with the other DDR requirements in R7 through R10, but do not agree with and specifically have a question on R11.1. R11 requires TO and GO to set their DDRs (that do not have continuous recording capability) to trigger under specific conditions. R11.1 simply states for rate-of-change of frequency only, but does not specify what rate is it that the DDR should be triggered to start recording. Do we need a default frequency rate-of-change to be specified in R11.1?No, the identified items need not be assigned as independent subrequirements. b) For R10, the implementation caveat should not be part of the requirement. Rather it should be included as part of the Implementation Plan. c) The SRC would also suggest that Requirement 9 be separated into two independent requirements - one for TOs and one for GOs. Although the intent to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R7 and R8 criteria.
Response: Thank you for your comments. a) The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. b) The SDT agrees with the recommendation and pulled the date from the requirement and will place it in the revised implementation schedule. c) The revised requirements have the Planning Coordinators or Reliability Coordinators select the DDR locations. The Transmission Owners and Generator Owners are requiredto provide DDR functionality at the locations specified by the Planning Coordinators and record data on the specified Elements.		
SPP System Protection and Control Working Group	No	a) 1) Please clarify R 10 and R 11 with respect to date (January 1, 2011). One suggestion is to have R11 listed before R10.2) b) Specify the actual trigger value in R 11.1
Response: Thank you for your comments. a) The SDT pulled the date from the requirement and will place it in the revised implementation schedule The standard applies to legacy equipment that meets the requirements. b) The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.		

Organization	Yes or No	Question 12 Comment
Members of the WECC Disturbance Monitoring Work Group	No	**a)** The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response: Thank you for your comments. a) The draft standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
PacifiCorp	No	a) The installed equipment of the neighboring (interconnected) entity should be included in the parameters of R7 ".no further than two substations away..". to provide an overlay between Transmission owners. b) Similar to comment 11. above. We also support WECC's comments responsive to this question.
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. b) See response to comments of referenced sections.		
Bonneville Power Administration	No	a) R9.2 Change to clarify "Sampling" (vs. "collecting") at 960 samples/second, in the slide presentation.R11.2 b) BPA does not think the oscillation trigger is viable - remove this requirement, or indicate better that if an optional oscillation detector is installed then set it per R11.2 requirements. c) Change R12 to say "shall time synchronize all of its Allow for additional/future triggers, frequency set point level vs. rate of change. d) Change R11.3 to have record length include pre-trigger event of 30 seconds to 1 minute.
Response: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power		

Organization	Yes or No	Question 12 Comment
flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1. b) & d) The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. c) The SDT added the word "time" synchronize to now Requirement R1.		
PG&E System Protection	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
NERC	No	a) R7 For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1: then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above, the Transmission Owner shall record..."The parenthetical qualifiers in both R7.3 and R7.3 should read: (for each transmission element operated at 200 kV and above) b) R9.2 The term collect in the sample rate requirement of R9.2 can be confused with what is required for values required to be stored. R 9.3 speaks to storage reuquirements. For clarity, R9.2 should read: Sample at least 960 times per second to calculate RMS electrical quantities.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
NYISO	No	We agree with the minimum requirements set in R9 for all DDRs. a) R11.1 What is supposed to be captured with this trigger? A ROC trigger won't consistantly capture the events causing step changes in frequency. A delta frequency trigger is more effective for capturing drops/rises in frequency. We propose requiring a trigger for delta frequency/step change in frequency for all new equipment, and for existing equipment that meets R9 and has the capability. b) R11.2 Not all existing recorders have this capability. Require this trigger for existing recorders that meets R9 and has the cabability. R11.3 Not all existing recorders have this capability. c) Require 3 minute recordings for existing equipment with this capability, and 60 second post trigger recordings for existing recorders that meet R9, but cannot store 3 minute records.
Response: Thank you for your comments. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
Portland General Electric	No	a) The following comments are those filed by the DMWG which we are filing in support: The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per		

Organization	Yes or No	Question 12 Comment
second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
Puget Sound Energy	No	a) The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirment eliminates the use of this adequate equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
Schneider Electric	No	a) The need to record and store continuously captured waveforms seems to be in excess. Triggered waveforms would suffice. Why the need to continuously record?
Response: Thank you for your comments. Captured waveforms are not required or specified for DDR. Sampled input waveforms for DDR are not required to be stored continuously but rather the standard does require the continuous recording of the output according to the date in the implementation schedule. Continuous recording capability is not requirement for FR functionality.		
Independent Electricity System Operator	No	a) We agree with the other DDR requirements in R7 through R10, but do not agree with/have a question on R11.1. R11 requires TO and GO to set their DDRs (that do not have continuous recording capability) to trigger under specific conditions. b) R11.1 simple states for rate-of-change of frequency only, but does not specify what rate is it that the DDR should be triggered to start recording.
Response: Thank you for your comments. The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range If the recorder does not have continuous recording capability, it shall set to record data for a minimum of three minutes.		
NV Energy	No	a) I agree with the terms. However, nothing is mentioned in the standard about the acceptable format that the DDR continuous data must be. The WECC uses the BPA stream reader format, while others use the IEEE C37.118-2006 format. I think this is the place to state and consolidate formats, similar to the COMTRADE requirement for the fault

Organization	Yes or No	Question 12 Comment
		recorder data.
Response: Thank you for your comments. Yes, the format of the submitted data is important. The requirement for the submittal data in a COMTRADE format provides consistency to facilitate the analysis of system disturbances. This information is listed in Section D, 1.5.1 of the draft standard. The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. In addition, PMUs are excluded in the approved SAR.		
DTE Energy/Detroit Edison	No	Please see comments for 9.
Response: Thank you for your comments. Please see our response to your comment to Question 9.		
ITC Transmission, METC	No	R9.1 is redundant to R7.3, R8.3 which indicate that the current monitored is required to be from the same phase as the voltage monitored. This redundant requirement may lead to double jeopardy.
Response: Thank you for your comments. The SDT agrees that the requirement is redundant and deleted old Requirement R9 part 9.1.		
NV Energy (fka Sierra Pacific Resources)	No	Sample rate of 960 samples per second in R9.2 is higher than is needed for reliability and would antiquate the investment already made at numerous substations. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the Glossary and the 960 samples per second requirement precludes the use of this existing equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. The SDT is using the NERC Glossary definition for DME.		
Salt River Project	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. The SDT is using the NERC Glossary definition for DME.		
Pacific Northwest National Laboratory	No	a) 12A. The term "collect" in R9.2 seems unclear--does it mean "measure and store (for subsequent off-line analysis)," or does it mean "measure as an input for on-line RMS calculations" 12B. For either interpretation of R9.2, the 960 sps requirement is an arbitrary value that seems unnecessarily high. The WECC WAMS contains DDR units that usually record point-on-wave and controller data at 960 sps, but these units also produce quite usable records when operated at 240 sps--what are the information targets, and what are the cost constraints? Phasor measurement units and other digital transducers can produce quite acceptable data with input rates below 960 sps, ESPECIALLY if their output rate is a mere (and unacceptably low) 6 sps.12C. In R9.3, 6 sps recording is almost too slow to be useful in a DDR. R6.2 requires at least 16 samples per 60 Hz cycle in fault recording--it is not unreasonable to seek a similar number of samples for each cycle of the highest swing frequency that a DDR should record. This rounds off nicely at 30 sps.12D. Extend R10 to read ". . . continuous recording at 30 sps. Future versions of this Standard may require 60 sps at some locations."12E. b) Consider specifying additional triggers in R11.1 (continued frequency offsets, steps in voltage or line flow, manual triggers, . . .)12F. c) Change R11.3 to read "Set data record lengths at a minimum of three minutes, plus at least one minute of pre-trigger data." A further requirement for trigger continuation should be considered for persistent oscillations or continued frequency offsets.
Response: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. c) Requirements state that each Transmission Owner and Generator Owner that has a DDR device functionality that meets the Planning Coordinator or Reliability		

Organization	Yes or No	Question 12 Comment
Coordinator DDR monitoring requirements and does not have continuous recording capability shall set data record lengths at a minimum of three minutes. The standard does not specify pre-trigger or post-trigger lengths for DDR.		
Hydro-Québec TransEnergie (HQT)	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) Referring to Requirement R8, as noted in the response to Question 5 and elsewhere, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. We have no comment to Requirement R9. d) Our response to Question 2 deals with Requirement R10. e) Requirement R11 should be reworded to: that does not have continuous recording capability shall set its device to trigger and record according to the following where available: Requirement R11.1 should be worded to:R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.
Response: Thank you for your comments. a) SDT is accounting for legacy equipment through triggered records, reflected in the updated standard. b,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. d) See our response to your comment in Question 2. e) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range		
Entergy Services, Inc	No	R10 states DDR devices installed after 1-1-11 shall be capable of continuous recording. It is not clear when continuous recording would be required to begin.
Response: Thank you for your comments. The latest revision of the standard states the effective dates for continuous recording. These requirements take effect the first day of the first calendar quarter one year after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required.		
Northeast Utilities	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) Referring to Requirement R8, it's possible for remote locations in a system to have a high concentration of

Organization	Yes or No	Question 12 Comment
		generation spread across several busses. It would seem appropriate to require recorders in such areas. c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. d) Referring to Requirement R9.3, does this need to be stored if the values can be derived from the record e) Response to Question 2 deals with Requirement R10. f) Requirement R11 should be reworded to: that "does" not have continuous recording capability shall set its device to trigger and record according to the following "where available": g) Requirement R11.1 should be worded to: R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.
Response: Thank you for your comments. a) SDT is accounting for legacy equipment through triggered records, reflected in the updated standard. B,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. d) To clarify, the standard states the requirement to record electrical quantities specified for DDR data. e) Updated dates are described in the Implementation Plan. f) & g) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
San Diego Gas and Electric Co.	No	The requirement in R9.2 to collect 960 samples per second seems high for the purpose of reliability.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		

Organization	Yes or No	Question 12 Comment
New York Independent System Operator	No	a) (R9) We request that the team add a new provision stating that all required DDR channels at a location should be recorded whenever a trigger asserts on any one of them, even where the channels are distributed across multiple DDR units.(R10) what exactly do the words "to meet requirements R7, R8, and R9" have to do with all this? b) We propose removing the reference to R7, R8, R9 and simply require continuous recording ability for newly installed DDRs The requirement of recorders installed after Jan 1, 2011 being able to continuously record would be redundant for the NPCC which requires recorders installed after Jan 1, 2009 to be continuous recorders. This will lead to confusion for some people and we propose adding some words describing such a situation and clarifying the requirements in such a case.(R11.1) c) It is our experience that rate-of-change in frequency is actually not a good DDR trigger. It produces many records for highly local events and may not catch significant disturbances. Delta Frequency is a proven DDR trigger, and performed admirably during the 2003 blackout. A good guideline for a delta frequency trigger would be to set to detect a sudden frequency change of 20 mHz. We suggest R11.1. should be written for delta frequency triggering with the aforementioned guideline for setting. Rate-of-change in frequency should not be mentioned in this standard. Rate-of-change in frequency is not a general name which includes delta frequency. (Refer to FDAC www.truc.org 2006 Conference paper: Frequency Triggers.) (R11.2) Not all existing recorders have this capability. Require this for existing recorders that have the capability and future installations.(R11.3) Not all existing recorders have this capability. Require minimum of 3 minutes for recorders with the capability, and 60 seconds for the minimum post trigger record length for all others.
Response: Thank you for your comments. a) Cross Triggering of multiple devices will not be included as a requirement. The future implementation of continuous recording capabilities required in Requirement R24 (old Requirement R10) will eliminate the need for it. b) PRC-002-1 requirements are not mandatory and enforceable. The SDT does not expect that the use of a different date in this proposed standard, PRC-002-2, will deter the present installation of continuous recording equipment for new or retrofit installations as may be required by regional criteria or regional standards. c) SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.		
E.ON U.S.	No	a) The GO should be required to collect current and voltage data relative to the triggering event (i.e. change of breaker position). b) The format should be given in either CSV or plain text, which can be analyzed by any system. Rather than having all time-stamped current and voltage data recording equipment accommodate a certain IEEE format, the available data could be submitted in CSV/plain text and later analyzed in the IEEE format.

Organization	Yes or No	Question 12 Comment
		c) Also, in Section A part 5 of the standard, the effective date for both 50% and 100% compliance is stated as [t]he first day of the first calendar quarter four years after applicable Regulatory Approval It would be more reasonable to require 100% compliance in, for example, 8 years and lrequire 50% compliance in 4 years. This would allow sufficient time to do the necessary engineering, acquiring of equipment, etc. to meet the requirements of this standard.
Response: Thank you for your comments. a) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. b) The requirement for the submittal data in a COMTRADE format provides consistency to facilitate the analysis of system disturbances. Conversion of CSV or plain test to a COMTRADE format should not be an obstacle to data transfer. c) The effective dates have been modified and are determined by the need for Implementation within the five year cycle of locations determined by the Planning Coordinators or Reliability Coordinators.		
Arizona Public Service Co.	No	R9.2 requires sampling at 960 samples per second. There are many DDR devices in service presently that have lower sample rates that provide perfectly adequate data. For example, there are many Macrodyne PMUs in service that have a 720 Hz sample rate and a data storage rate of 30 Hz. These PMUs should either be grandfathered or requirement should be reduced to allow them to meet the criteria. Don't require people to replace adequate equipment that gives acceptable results.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
Tucson Electric Power	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities.		

Organization	Yes or No	Question 12 Comment
The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you. See response to the IRC SRC comments.		
Utility System Efficiencies, Inc.	No	a) The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes a DDR frequency response of 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second (point on wave) provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and this change to require 960 samples per second eliminates the use of this adequate equipment.12A. The term "collect" in R9.2 seems unclear--does it mean "measure and store (for subsequent off-line analysis)," or does it mean "measure as an input for on-line RMS calculations?" 12C. In R9.3, 6 sps recording is almost too slow to be useful in a DDR. R6.2 requires at least 16 samples per 60 Hz cycle in fault recording--it is not unreasonable to seek a similar number of samples for each cycle of the highest swing frequency that a DDR should record. This rounds off nicely at 30 sps.12D. Extend R10 to read ". . . continuous recording at 30 sps. Future versions of this Standard may require 60 sps at some locations."12E. b) Consider specifying additional triggers in R11.1 (continued frequency offsets, steps in voltage or line flow, manual triggers, . . .)12F. Change R11.3 to read "Set data record lengths at a minimum of three minutes, plus at least one minute of pre-trigger data." A further requirement for trigger continuation should be considered for persistent oscillations or continued frequency offsets.
Response: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		

Organization	Yes or No	Question 12 Comment
British Columbia Transmission Corporation	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
Kansas City Power & Light	No	R10 is part implentation plan or effective date and part requirement. The requirement is a DDR device capable of continuous recording to meet requirements R7 through R9. The effective date is January 1, 2011. Request the SDT remove the effective date part from R10 and put that in section A. In addition, the Effective Date part of Section A is either incorrect or may be conflicting with the January 1, 2011 expectation by including R11 with a 50% compliance in two years and 100% compliant in four years after regulatory approval. Please consider the intentions and revise the Effective Date part of Section A to accurately reflect the SDT intentions regarding implementation of the requirement part of R10.
Response: Thank you for your comments. The effective dates have been modified and are determined by the need for Implementation within the five year cycle of locations determined by the Planning Coordinators or Reliability Coordinators.		
PNM	No	
PHI (PEPCO Holdings Inc.)	Yes	It should be clarified that if all 3 phase bus voltages are monitored, the monitored phase current for each of the lines do not all have to be on the same phase.
Response: Thank you for your comments. The standard has been revised to include single phase-neutral or positive sequence voltage.		
Florida Power & Light	Yes	a) The term continuous recording should be technically defined. Obviously a true continuous record can not be retrieved or stored locally for long periods. Continuous records must be retrievable in sections. The expectations of continuous recording need to be well defined to determine compliance if for no other reason to provide audit ability.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The SDT clarified that continuous recording is assigned to DDR functionality only and the DDR sampling and storage rate apply.		
Dominion	Yes	a) To make this clearer, reword R.7 to start with location requirements rather than exceptions. If we use a table under R1 and R4 then use a similar table under R7. b) Also, under R11.3, the pre-trigger record length and post-trigger record length should be specified (what part of the 3 minutes should be pre and post trigger).We suggest that the pre-trigger and post-trigger be a minimum of 1 minute each with total record at least 3 minutes
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
SERC Protection and Controls Sub-committee	Yes	a) To make this clearer, reword R.7 to start with location requirements rather than exceptions. b) Also, under R11.3, the pre-trigger record length and post-trigger record length should be specified (what part of the 3 minutes should be pre and post trigger?).
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response: Thank you for your comments. See reply to the SERC PCS.		

Organization	Yes or No	Question 12 Comment
MRO NERC Standards Review Subcommittee	Yes	
Grant County PUD	Yes	
Duke Energy	Yes	
US Bureau of Reclamation	Yes	
Beckwith Electric Co	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
Xcel Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Progress Energy Florida	Yes	
American Electric Power	Yes	
FirstEnergy	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	
Exelon Generation LLC	Yes	

Organization	Yes or No	Question 12 Comment
JEA	Yes	
City of Tallahassee (TAL)		No expertise to provide input.
Response: Thank you.		
Wisconsin Electric		
WECC		
CenterPoint Energy		
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
Brazos Electric Power Cooperative, Inc.		
SERC Engineering Committee Planning Standards Subcommittee		

General Questions

13. Do you agree with the Other Disturbance Monitoring Requirements R12 and R13 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration: While a majority of the responses were in favor of these time synchronization and data retention requirements, there were some requests for clarification. The standard drafting team has addressed those with the following:

- The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.
- The last phrase of Requirement R12 (now Requirement R1), “with the associated hour offset,” allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.
- Disturbance data shall be stored for a minimum of 10 calendar days following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).

Several comments unrelated to the issues above were also received and the standard drafting team provided responses to those comments below.

Organization	Yes or No	Question 13 Comment
IRC Standards Review Committee	No	The SRC questions the use as Universal Coordinated Time in R12 as a reliability issue. Having UCT for every device may make it "easier" for an after-the-fact collection of DDR data, it does not address the fact that other data would not be on UCT, and that a team should be able to adjust for time differences rather than to subject someone to financial penalties even though it had the data it did not have the proper time zone defined.
Response: Thank you for your comments. The last phrase of Requirement R12 (now Requirement R1), “with the associated hour offset,” allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.		
Tri-State Generation and Transmission Association	No	Data should be retained longer than 10 calendar days. We would suggest 60 days as a minimum.

Organization	Yes or No	Question 13 Comment
Response: Thank you for your comments. The 10 days required by the standard is a minimum. Entities are free to retain data for longer periods or indefinitely if they choose.		
Wisconsin Electric	No	The intent of R13 is not clear to us. This seems to be a data retention requirement.
Response: Thank you for your comments. R13 is indeed a data retention requirement and is necessary to recreate an event after a Disturbance in a timely fashion. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
City of Tallahassee (TAL)	No	R13; The NERC definition of Disturbance is too vague for this standard. Any minor hiccup on the grid or even local area could be interpretted as a Disturbance.
Response: Thank you for your comments. The SDT thinks that the definition, while broad, is appropriate for use in the standard.		
San Diego Gas and Electric Co.	No	In R12, the criteria is to synchronize SOE, FR, and DDR functions to within +/- 2ms of UTC, but earlier in R3, the criteria for time-stamping changes in breaker position is to be within 4ms of UTC. We would suggest making both of the criteria to be within 4ms of UTC.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
New York Independent System Operator	No	(R12) This requirement mainly concerns synchronizing with UTC Time Scale. The words with the associated hour offset have to do with Time Zone and should be removed from this sentence and placed in a separate sentence or a separate requirement. We suggest keeping these two concepts separate, both in the interest of clarity, and to facilitate future adjustments in wording. This area is covered in the report of IEEE PSRC I11 which is among the drafting team references. Two acceptable separate sentences or requirements would be as follows: Each TO and GO shall synchronize all of its SOE, FR, and DDR functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) Time Scale. Within time sequence data files produced by SOE, FR, and DDR functions, and within filenames, time shall be expressed in 24 hour format, and with no local offset, or with some number of positive or negative local hour(s) of local offset. Each filename, in conforming to C37.232-2007 COMNAMES (See D. 1.5.1) must contain this offset information. Since C37.111-1999 COMTRADE does not include the offset within the .cfg file, and until this issue is addressed in a revision to COMTRADE, the offset in the filename shall be interpreted, for purposes of compliance with this standard, to apply to the time sequence data in the file. On the last point, the drafting team is perhaps aware that an IEEE PSRC working group H4 is making revisions to C37.111-1999

Organization	Yes or No	Question 13 Comment
		COMTRADE, and is considering addition of local offset to the COMTRADE .cfg file.
Response: Thank you for your comments. The SDT does not agree with the recommended rewording because UTC with local offset is used by many operating centers.		
E.ON U.S.	No	E ON US objects to the compliance timetable of immediate to 18 months after NERC Board of Trustees or FERC approvals. More time is required to properly design, procure and install the disturbance monitoring equipment necessary to meet the proposed requirements, particularly in light of the uniqueness of the existing facilities and equipment to which the requirements apply.
Response: Thank you for your comments. The SDT has revised the implementation schedule to allow transition time to become compliant with the requirements.		
Arizona Public Service Co.	No	Earlier in R3 you specify +/- 4 ms
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
JEA	No	Certain DFR equipment, especially microprocessor relays used for DFR functionality, have limited storage. The relay equipment storage buffers for oscillographic information may be overwritten by new data in a roll over buffer and will not be available for the 10 day period. For SOE and DDR data the ten day storage requrienment should be easily met, but not for relay DFR equipment.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. The last phrase of Requirement R12 (now Requirement R1), “with the associated hour offset,” allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.		
CenterPoint Energy	No	The FERC-approved NERC reliability standard FAC-003 for Vegetation Management includes allowances for certain situations resulting from natural disasters, such as tornados and hurricanes. This proposed standard does not address the enormous quantities of data, as well as the complications, that arise in such natural disasters. CenterPoint Energy recommends reviewing the various requirements and including appropriate allowances to

Organization	Yes or No	Question 13 Comment
		address natural disaster situations.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
Kansas City Power & Light	No	It is not possible to guarantee DME data will be available 10 calendar days after an event in R13. Considering the number of triggers involved setting off the collection of relevant date and the collection of relevant data and the limits of the storage of DME equipment, it is possible in storm situations where there can be so many triggered instances, the data for an event of interest may not be present. Request the SDT consider revising this requirement to require entities to retreive the DME data that is stored (either remotely or locally) within 10 calendar days of an event. What this does is remove the requirement to ensure the data of interest is there and emphasizes the need to retrieve data before it is lost. In addition, please clarify the definition of a "Disturbance" referred to in R13. Is it according to Table 1 in EOP-004-1?
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device). The SDT is using the definition of Disturbance found in the NERC Glossary of Terms.		
Florida Power & Light	Yes	Please see comments for question 17.
Response: Thank you for your comments. Please see response for question 17.		
PG&E System Protection	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		

Organization	Yes or No	Question 13 Comment
Puget Sound Energy	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard is silent on equipment.		
Salt River Project	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Pacific Northwest National Laboratory	Yes	In R12, bear in mind that DDR units which are closely synchronized at their INPUTS are not necessarily synchronized at their OUTPUTS. E.g., the processing lag through a PMU can vary by 30 msec or more between different PMU types even when they are all operating at 30 sps. If properly filtered, the relative processing delay for 6 sps data would probably be something like 50 msec. These timing inconsistencies can be very important when developing an integrated profile of system dynamic behavior.
Response: Thank you for your comments. The SDT thinks that the commenter's processing delay concern is related to equipment configuration, and since the standard does not address specific equipment, it falls outside the scope of the SDT. In addition, PMU application is excluded in the SAR.		
Northeast Utilities	Yes	Referring to Requirement R13, it could be read to mean that one only needs to keep data for 10 days. We believe it was intended to say the device shall have the storage to retain records for 10 days.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
Tucson Electric Power	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Duke Energy	Yes	DDR data will overwrite after 10 days, in some instances.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		

Organization	Yes or No	Question 13 Comment
Utility System Efficiencies, Inc.	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.Also, in R12, bear in mind that DDR units which are closely synchronized at their INPUTS are not necessarily synchronized at their OUTPUTS. E.g., the processing lag through a PMU can vary by 30 msec or more between different PMU types even when they are all operating at 30 sps. If properly filtered, the relative processing delay for 6 sps data would probably be something like 50 msec. These timing inconsistencies can be very important when developing an integrated profile of system dynamic behavior and should be addressed by this Standard.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment. The SDT thinks that the commenter's processing delay concern is related to equipment configuration, and since the standard does not address specific equipment, it falls outside the scope of the SDT. In addition, PMU application is excluded in the SAR.		
SPP System Protection and Control Working Group	Yes	1. Please clarify the definition of Disturbance. Is it according to Table 1 in EOP-004-1?
Response: Thank you for your comments. The SDT is using the definition of Disturbance found in the NERC Glossary of Terms.		
Members of the WECC Disturbance Monitoring Work Group	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Southern Company - Transmission	Yes	No further comment.
MRO NERC Standards Review Subcommittee	Yes	
Dominion	Yes	
FirstEnergy	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 13 Comment
NERC	Yes	
SERC Protection and Controls Sub-committee	Yes	
US Bureau of Reclamation	Yes	
NYISO	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
ITC Transmission, METC	Yes	
Independent Electricity System Operator	Yes	
Grant County PUD	Yes	
American Electric Power	Yes	
Bonneville Power Administration	Yes	
NV Energy	Yes	
Schneider Electric	Yes	
Progress Energy Florida	Yes	
Progress Energy Carolina, Inc.	Yes	

Organization	Yes or No	Question 13 Comment
Hydro-Québec TransEnergie (HQT)	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
Entergy Services, Inc	Yes	
British Columbia Transmission Corporation	Yes	
Exelon Generation LLC	Yes	
Xcel Energy	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Northeast Power Coordinating Council	Yes	
Cowlitz County PUD	Yes	
SERC Engineering Committee Planning Standards Subcommittee		
TransAlta		
National Grid		
DTE Energy/Detroit Edison		
Brazos Electric Power Cooperative,		

Organization	Yes or No	Question 13 Comment
Inc.		
Los Angeles Department of Water & Power		
WECC		

General Questions

14. Are you aware of any regional variances that would be required as a result of the proposed standard?

Summary Consideration: Commenters were not aware of a variance for this standard at this point of its development. The SDT reminds commenters that entities are not precluded from developing more stringent criteria. Establishing a lower cutoff for a proposed NERC standard requirement is simply a variance of that requirement and not appropriate for inclusion in a regional standard. Any region that believes it is appropriate to establish such levels needs to decide whether developing a regional criteria or submitting it as a variance to the SDT best suits their situation.

Organization	Yes or No	Question 14 Comment
NERC	No	For reasons of consistency in the ability to cross-regional or interconnection-wide disturbance analysis, there should be no regional variances.
Response: The SDT thanks you for your comment.		
DTE Energy/Detroit Edison	No	Will regional variances be included in this standard?
Response: Thank you for your comment. As of this last posting, the SDT had not received any variance requests for this standard.		
Entergy Services, Inc	No	Not as proposed, but there should be for DDR applications.
Response: Thank you for your comment. As of this last posting, the SDT had not received any variance requests for this standard.		
Northeast Power Coordinating Council	No	
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	No	

Organization	Yes or No	Question 14 Comment
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
PacifiCorp	No	
Bonneville Power Administration	No	
FirstEnergy	No	
Florida Power & Light	No	
Los Angeles Department of Water & Power	No	
MRO NERC Standards Review Subcommittee	No	
PG&E System Protection	No	
Grant County PUD	No	
NYISO	No	
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	Question 14 Comments:
Progress Energy Florida	No	

Organization	Yes or No	Question 14 Comment
Schneider Electric	No	
Independent Electricity System Operator	No	
American Electric Power	No	
NextEra Energy Resources (formerly FPL Energy)	No	
Manitoba Hydro	No	
Exelon Generation LLC	No	
Wisconsin Electric	No	
ITC Transmission, METC	No	
City of Tallahassee (TAL)	No	
NV Energy (fka Sierra Pacific Resources)	No	
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Northeast Utilities	No	
New York Independent System Operator	No	
JEA	No	

Organization	Yes or No	Question 14 Comment
Beckwith Electric Co	No	
Duke Energy	No	
Xcel Energy	No	
Kansas City Power & Light	No	
PNM	No	
SERC Protection and Controls Sub-committee	Yes	See comment on response #1.
Response: Thank you for your comments. For Question 1, you commented: "But we believe that the regional "Stability" group needs to decide on the locations of the DDR's based on a NERC defined methodology." Allowing a regional stability group to define the locations is considered a fill-in-the-blank requirement. The SDT formed a task team dedicated to requesting and analyzing transmission system data. The SDT used the task team analysis results to establish revised criteria for locations.		
Dominion	Yes	We support the 200 kV cutoff. However, some regions have indicated the 200kV threshold is not appropriate and indicate a preference for a lower criteria. We believe that if the regions desire to require more granularity, that criteria should be applied in a regional standard which can be more restrictive and should be supported by a technical basis
Response: Thank you for your comments. Entities are not precluded from developing more stringent criteria. The SDT formed a task team dedicated to requesting and analyzing transmission system data and used the task team analysis results to establish revised criteria for locations.		
PHI (PEPCO Holdings Inc.)	Yes	PRC-002-RFC-01, draft 11, requires DM for single generating units 250MVA and above, and/or aggregate plant capacity of 750MVA and above.
Response: Thank you for your comment. Since this NERC DM standard has not been fully developed, Reliability*First* can develop and seek approval of its standard in accordance with approved Standard Development Procedures. Reliability*First* is encouraged to track the development of this standard and to consider if it wishes to continue to support and justify a more stringent MVA level of the developing NERC proposal and request a variance accordingly. The SDT formed a task team dedicated to requesting and analyzing transmission system data and used the task team analysis results to establish revised criteria for locations.		

Organization	Yes or No	Question 14 Comment
US Bureau of Reclamation	Yes	
Alberta Electric System Operator	Yes	
NV Energy		As stated previously, the DDR data format differs from region to region and should be standardized.
Response: Thank you for your comment. Data file formatting is not the subject of "what" is required by the standard, but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated are at the discretion of the users.		
Puget Sound Energy		
National Grid		
Members of the WECC Disturbance Monitoring Work Group		
Pacific Northwest National Laboratory		
Salt River Project		
WECC		
Portland General Electric		
TransAlta		
Brazos Electric Power Cooperative, Inc.		
Arizona Public Service Co.		

Organization	Yes or No	Question 14 Comment
San Diego Gas and Electric Co.		
E.ON U.S.		
Tucson Electric Power		
CenterPoint Energy		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		

General Questions

15. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration: Commenters were generally unaware of any specific regulatory concerns; however, it was pointed out that the potential incremental financial impact may need to be considered before approval.

Organization	Yes or No	Question 15 Comment
Northeast Power Coordinating Council	No	
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	No	
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
SERC Protection and Controls Sub-committee	No	
PacifiCorp	No	
Bonneville Power Administration	No	
FirstEnergy	No	
Florida Power & Light	No	

Organization	Yes or No	Question 15 Comment
Los Angeles Department of Water & Power	No	
MRO NERC Standards Review Subcommittee	No	
NERC	No	
NYISO	No	
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	
Progress Energy Florida	No	
Schneider Electric	No	
Independent Electricity System Operator	No	
NextEra Energy Resources (formerly FPL Energy)	No	
Manitoba Hydro	No	
Exelon Generation LLC	No	
NV Energy	No	
ITC Transmission, METC	No	
City of Tallahassee (TAL)	No	

Organization	Yes or No	Question 15 Comment
PHI (PEPCO Holdings Inc.)	No	
NV Energy (fka Sierra Pacific Resources)	No	
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Entergy Services, Inc	No	
Northeast Utilities	No	
New York Independent System Operator	No	
JEA	No	
Alberta Electric System Operator	No	
Beckwith Electric Co	No	
Duke Energy	No	
Xcel Energy	No	
Kansas City Power & Light	No	
Dominion	Yes	Concern that FERC standards and code of conducts, as well as some RTO/ISO rules may prohibit the GO from access to system monitoring data necessary to participate in disturbance analysis studies.
Response: Thank you for your comment. The purpose of this standard is to ensure that disturbance data is available and does not establish requirements for disturbance analysis studies. The conditions under which the data is used, why it is used, and by which entity it is used are as diverse as the range of disturbances and system configurations. Since neither this standard, nor its predecessors, established "what" analyses are required and by which entity, it was not possible to		

Organization	Yes or No	Question 15 Comment
establish reporting "requirements" which are really a matter of "how" the available information can be communicated and utilized.		
American Electric Power	Yes	The additional costs imposed by implementing this standard represent a financial risk to the utility. In the regulatory process, increased costs in tariffs and rate schedules are evaluated for recovery on a cost-benefit basis by the applicable regulatory authority. Additionally, such costs are subject to regulatory lags in the period before such cases are heard by this authority.
Response: Thank you for your comment. The SDT understands your concern in the context of FERC-approved PRC-018-1, which required adding time synchronization. The extent of incremental installations resulting from approval of this standard over that resulting from current standards and criteria is unknown at this time, as the SDT is still developing the technical requirements. This standard is being developed to address reliability issues and serves to improve reliability; therefore, associated implementation costs should be justifiable.		
US Bureau of Reclamation	Yes	
Arizona Public Service Co.		WECC has had a disturbance monitoring plan for many years. As part of this plan they have required PMUs at certain locations. The PMUs that were "approved" include some that would not meet the R9.2 requirement as discussed earlier. This would create a conflict between what WECC agreed was acceptable and what this standard proposes.
Response: Thank you for your comment. The SDT is unable to determine from your comments whether the WECC requirements are more stringent. If those requirements are more stringent, the proposed standard requirements would not preclude those regional requirements from continuing. The entities would have only to demonstrate that they meet the standard requirements.		
PG&E System Protection		
TransAlta		
Puget Sound Energy		
DTE Energy/Detroit Edison		
Portland General Electric		
National Grid		

Organization	Yes or No	Question 15 Comment
Wisconsin Electric		
Pacific Northwest National Laboratory		
Salt River Project		
WECC		
San Diego Gas and Electric Co.		
E.ON U.S.		
Members of the WECC Disturbance Monitoring Work Group		
Tucson Electric Power		
Brazos Electric Power Cooperative, Inc.		
CenterPoint Energy		
Grant County PUD		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
PNM		

General Questions

16. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Consideration: Commenters provided a wide range of additional questions and comments. A majority of those comments are addressed as follows:

- Compliance Section 1.3.2 and 1.5 are in the Compliance section because they are supporting documentation to demonstrate compliance with the requirements.
- TOs and GOs are required to document and apply a triggering methodology for FR and DDR in the latest revision of the standard.
- The SDT revised the requirements to split the TO and GO requirements into separate requirements to more distinctly address ownership. The standard cannot address all issues with joint ownership. It is up to the owners to address these issues.
- The purpose of the standard is to ensure that data is available to analyze wide area events. Natural disasters may generate large amounts of data and the TO or GO is expected to have that data available. The standard does not state that all of the monitoring equipment must produce data for every event. In the event that a natural disaster, which is considered an act of god, destroys the monitoring equipment and data is not available, as long as data is available from other monitoring location, the intent of the standard's requirements is still met.

Organization	Yes or No	Question 16 Comment
Cowlitz County PUD	No	Typo above, it is 16.
Response: The SDT does not understand this comment.		
ITC Transmission, METC	No	
NV Energy (fka Sierra Pacific Resources)	No	
Arizona Public Service Co.	No	
Manitoba Hydro	No	

Organization	Yes or No	Question 16 Comment
Tri-State Generation and Transmission Association	No	
US Bureau of Reclamation	No	
Wisconsin Electric	No	
NV Energy	No	
Beckwith Electric Co	No	
Florida Power & Light	No	
NextEra Energy Resources (formerly FPL Energy)	No	
JEA	No	
SERC Protection and Controls Sub-committee	No	
PHI (PEPCO Holdings Inc.)	No	
SERC Engineering Committee Planning Standards Subcommittee	No	
Southern Company - Transmission	No	No further comment.
Northeast Power Coordinating Council	Yes	Regarding Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data, as we commented in Question 5 and elsewhere performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. We do not feel that the 200kV threshold, nor the plant/plants' capacities are appropriate criteria for assessing criticality. This should be reflected in the table.The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 16 Comment</th></tr>
<tr><td></td><td></td><td>greater than 1500MVA. As we commented in Question 5 and elsewhere we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. Table 2-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.</td></tr>
<tr><td>IRC Standards Review Committee</td><td>Yes</td><td>Compliance item 1.3.2 and 1.5 seem to be adding undocumented requirements. The standard focuses on data collection but does not require the data to be provided to anyone. Is it implied (from the Rules of procedure) that the data be provided to the ERO, and therefore no requirement is needed? Data Retention also adds undocumented requirements. Mandatory formats should not be part of a standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT considered this comment but decided to leave these items in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard.</td></tr>
<tr><td>SPP System Protection and Control Working Group</td><td>Yes</td><td>1)The proposed standard needs to include a statement to trigger a DFR on a fault. 2)Sections 1.3.2 and 1.5 from Section D (Compliance) are requirements so they need to be added in Section B (Requirement) 3) How does the requirements in this proposed standard apply to a substation jointly owned by two or more parties?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The proposed standard has been revised to add triggering requirements related to a fault on the transmission system.
2. The SDT has retained these items in the compliance section.
3. The Transmission Owner or Generator Owner can ensure that disturbance monitoring is furnished by contract with the other party.</td></tr>
<tr><td>Members of the WECC Disturbance Monitoring Work Group</td><td>Yes</td><td>1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.</td></tr>
</table>

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the stated format. The proposed standard will retain this requirement.		
PacifiCorp	Yes	1. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 2. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files? This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
FirstEnergy	Yes	1. The requirements as written may not take into account the actual entity that owns the equipment. If Transmission Owners installed the equipment relevant to their facilities, and Generation Owners did the same, duplicate monitoring may result. This isn't a problem as it pertains to the actual equipment monitored, but it potentially results in additional costs to the entities. Also, regardless of the NERC Functional Model definitions, there are many different actual equipment ownership arrangements between generation-only entities and the transmission entities to which they are connected. For example, a generation entity may or may not actually own the connection breakers in the transmission substation. We suggest throughout the standard that in all instances where a TO and/or GO "shall" do something, that the word "shall" be replaced with "shall ensure". This is the same wording used in the recently approved RFC DME standard PRC-002-RFC-01 which alleviated many stakeholder concerns regarding ownership and responsibilities for disturbance monitoring. 2. The Compliance Section 1.5 of the standard includes information that is presently contained in requirement R4 of the existing PRC-002-1 standard. We have reviewed the NERC Reliability Standards Development Procedure and it appears that the SDT may have appropriately placed much of the section 1.5 information in section D. Compliance of the reliability standard. The only item in question is the second bullet of section 1.5.1 which may be more appropriately placed in the requirements section. However, it is FirstEnergy's opinion that "after the fact" data submittal type of requirements such as the need to "submit within 30 days upon request" are administrative, have no reliability impact and in general should not be subject to penalties and fines. While the inclusion of this item within the Compliance section avoids the item being subject to the Sanctions Guideline, we ask the team to reconsider its placement in the standard.It is FirstEnergy's opinion that the reliability

Organization	Yes or No	Question 16 Comment
		standards need to evolve in such a way that clearly delineate reliability requirements from administrative requirements. We suggest subsections of section B "Requirements" labeled "1: Reliability Requirements" and "2: Administrative Requirements" and that the administrative requirements would generally receive "traffic ticket" warnings and only escalate to sanctions for repeat or willful violations. 3. The Purpose statement of the standard is missing the "reporting" aspect of this standard. We suggest the SDT change the Purpose statement to match the Purpose of the current PRC-002-1 standard and also detailed in the SAR: "To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models." 4. The proposed Applicability section details the facilities for which the standard is applicable. However, since the proposed requirements already properly point out the locations that require disturbance monitoring equipment, the applicability section could simply state the TO and GO with no additional qualifying language.
Response: Thank you for your comment. 1. The proposed standard has been revised to include ownership of the equipment to be monitored in the disturbance monitoring requirements. 2. The SDT considered this comment but decided to leave these items in the compliance section. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 3. The SDT considered this comment but decided not to change the purpose statement. The title of the standard reflects the reporting objective, but more importantly, the requirements contain the necessary reporting requirements between the entities responsible for DME. 4. The proposed standard has been revised in accordance with your comment.		
Los Angeles Department of Water & Power	Yes	Final issue for LADWP is the proposed effective dates, 100% compliance within 4 years. Like many other utilities, our company is limited in resources, including design and installation staff. A preliminary review of these proposed regulations and their affect to our system suggests the need to install several new Fault Recorders and Disturbance Monitoring systems. The amount of work required will likely exceed the 4 years proposed. LADWP may need to discuss scenarios of extending installation dates beyong the proposed 4 year window.
Response: Thank you for your comment. The proposed standard has been revised to require a less aggressive implementation schedule.		
PG&E System Protection	Yes	1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units was not. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file

Organization	Yes or No	Question 16 Comment
		names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
NERC	Yes	Effective Date R12-R13For consistency, the first bullet under Effective Dates should read: The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:"
Response: Thank you for your comment. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
TransAlta	Yes	SDT took consideration of the resources needed when choosing the criterion for selecting locations for monitoring/recording disturbance data. This can be shown in Table 1 of R4, Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal. So if a line has fault data recorded at its remote terminal, it is not required to record at the nearest terminal. But what about the remote terminal is connected to a generator owned by a GO Does that mean the location owned by the TO is excluded? If using this same approach, why cannot the terminal owned by a GO be excluded if the remote terminal has the fault data recorded? There are no such wordings in the requirements for GO's in the draft. So it is recommended that SDT review the disturbance monitoring/recording requirements at the location of interface between TO and GO.
Response: Thank you for your comment. The Tables have been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		
NYISO	Yes	Section A5 first sentence: "The First Day of the first calendar quarter four years after?" I think "four" was meant to be "two" such that it's consistant with the end of the sentence.R1.1 I found the sentence difficult to understand, change to the wording in the table under R4.2R5.5 there is an extra "d" in "?fault data recorded d at it's remote terminal"

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule. The tables have been removed.		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: 1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
Progress Energy Florida	Yes	R1.1 and Table 4-1 specifies substations that "contain any combination of 3 or more transmission lines operated >200kV AND TRANSFORMERS having primary and secondary voltage ratings of >200kV".Above, the words AND TRANSFORMERS is interpreted as the location must contain a transformer with primary and secondary voltages >200kV to be a required location. For example, as it's written this would mean the location needs to contain a 500/230kV transformer in addition to at least qty 2 - >200kV lines. A location with 5 >200kV lines and a non-qualifying 230/115kV transformer would not be a required location. If the word was OR a location with 3 >200kV lines would be a required location and would increase the 230kV substation requirement greatly. It is my opinion that these substations and associated >200kV lines do warrant monitoring because of their significance to the BES.R6.2 requires "16 samples per cycle", where R9.2 requires "960 samples per second". SDT should pick a common way to state sample rate. Table 4-1 the Location column specifies "transformers having primary AND secondary voltage ratings >= 200kV" where the Equipment column specifies "transformer having low-side operating voltage >= 200kV. Again, SDT should find a common way to state this requirement.
Response: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. Table 4-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		

Organization	Yes or No	Question 16 Comment
Puget Sound Energy	Yes	1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
Schneider Electric	Yes	The driver for this standard is to ensure that the data required for proper analysis is captured. In order to analyze events, data from multiple recorders and multiple locations will be required. Has the committee considered the differences in recording methods used between vendors and the resulting differences in data captured for the same event? Most countries specify IEC 61000-4-30 Class A devices to ensure that all devices (no matter the manufacturer or device type) will provide the same data for the same event. Has the committee considered this standard?
Response: Thank you for your comment. The SDT has considered the differences in recording methods used between vendors and resolved to allow for these vendor differences as long as the data is time stamped and sampled at the required rates or better. The SDT did not consider the IEC standard.		
Independent Electricity System Operator	Yes	R1 and R2 indicate the conditions under which SOE logging should be made, i.e. for changes in circuit breaker position. However, R4 and R5 as well as R7 and R8 do not say what the triggers for these recordings should be, e.g. a fault, a voltage sag or swell. We believe for consistency, reference should be made to some triggering conditions or events.
Response: Thank you for your comment. The proposed standard has been revised to add triggering requirements.		
American Electric Power	Yes	1.AEP would suggest the addition of the following wording where appropriate: Per the requirements of this standard, the equipment owner is responsible for disturbance monitoring and reporting unless the Transmission and Generation Owners have an alternative agreement to monitor interconnecting equipment. 2. Section 1.5

Organization	Yes or No	Question 16 Comment
		of the Section D should be moved into the technical requirement portion of the standard. These involve technical considerations. 3. Please remove bullet three (related to interposing relays). 4. The omission of "Measures" is of concern. A clear sight on measurement should be a part of requirement development, otherwise the objective will not be clear. 5 Additionally, for Effective Date, Requirements R1 through R11, first bullet, first line, should state "two," not "four" years to be consistent. Under Requirements R12 and R13, first bullet, third line, "eighteen months" should be inserted after the word "quarter" and "NERC" should be inserted before "Board." 6. To be clear, R4.2 (p. 6) should have "one winding of each monitored" added before the word "transformer" in line 2. 7. Page 7 contains a typographical error in the fourth row of table 5-1, in the first bullet of column two has a "d" following "recorded" in the fourth line. 8. The page 2 Future Development Plan, on item 7, should have "NERC" added before "Board." "NERC" should also be added before "Board of Trustees" in three locations in Section A-5.
Response: The SDT thanks you for your comments. 1. The SDT considered this comment but did not revise the proposed standard because the requirements should focus on what is required for reliability and not necessarily consider how they will be met (i.e. via agreement between responsible entities). 2. The SDT chose to retain these in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard. 3. The proposed standard has been revised in accordance with your comment. 4. The SDT plans to add measures with the second formal posting. 5. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule. 6. The SDT considered this comment but did not revise the proposed standard accordingly because the drafting team thinks it is clearly stated in the revised standard. 7. Table 5-1 has been eliminated in the revised standard. 8. The proposed standard has been revised in section A-5 but was not revised on page 2.		
Exelon Generation LLC	Yes	1. Effective date: What does 50% compliant means for a registered Generation Owner (GO) like Exelon that has multiple sites with each site consisting of a single or multiple units? In our case, some units may require DDRs while others may not. Does 50% compliance within two years means 50% of the units in the fleet have to be compliant within two years or does 50% compliant within two years means 50% of the required parameters/quantities to be monitored should be available within two years? We are trying to understand for Generation Owners, does 50% compliance apply to a unit or to a site or to registered GO as a whole? Please clarify. 2. Effective date: PRC-018-1 had a Requirement of 75% compliant within 3 years. Has that Requirement been dropped by PRC-002-2? 3. Effective date: Requirement R12 and R13 This needs to be

Organization	Yes or No	Question 16 Comment
		clarified that these effective dates are applicable to the already installed DME equipment for which GO/TO is taking or intends to take credit for meeting the requirements of this standard. These dates are not applicable to the new equipment. New equipment is allowed to be installed within 2 to 4 years of Regulatory approval. So installing synchronizing capability within 18 months of Regulatory approval, when equipment is not even installed yet, does not make sense.
Response: Thank you for your comment. 1. Data for required parameters/quantities for 50% of the designated locations to be monitored should be available within two years. 2. PRC-018 will be replaced by the proposed standard. The 75% requirement has been dropped by PRC-002-2. 3. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
DTE Energy/Detroit Edison	Yes	When will violation severity levels be added?
Response: Thank you for your comment. Violation Severity Levels will be added for the second formal posting.		
City of Tallahassee (TAL)	Yes	1. R10; Delete the reference to R9 to read "Each TO and GO that installs a DDR device after January 1, 2011 to meet R7 and/or R8 shall install a device that is capable of continuous recording." R9 is a data management requirement only. It is not used to require the installation of a device. OR combine R10 into R9. R10 is an additional technical specification that would put the specs in one requirement, even though it would be a sub-requirement. 2. Reiterate the need to move Section D Compliance items D.1.3.1, 1.3.2, 1.5.1 back into the requirements section.
Response: Thank you for your comment. 1. The SDT has revised the standard to clarify this wording in accordance with your comments. 2. The SDT has considered this comment. The SDT chose to retain these in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Pacific Northwest National Laboratory	Yes	16A. My primary concern is that the proposed Standard does not address data quality issues, or establish a lexicon for such a discussion. Tedious as they may seem, filtering and spectral content are essential performance factors to examine in any DDR [21].16B. I have a LOT of concerns about Compliance item 1.5.1. The .dst files presently used in PMU networks are efficient to the point of being elegant--how large would an equivalent COMTRADE file be?16C. Item 1.5.1 should have an additional bullet on configuration files:? All reported DDR data shall be accompanied by a configuration file (CF) providing the following primary

Organization	Yes or No	Question 16 Comment
		information: [143] - the data source to which the CF applies (name of the archiving device) - structure of the data source records (number of sensors, sensor names, number of signals for each sensor) - parameters for each signal: ~ sensor producing the signal (includes sensor model & firmware version) ~ signal type (voltage, current, other) ~ scale factors for conversion to engineering units ~ timing shift or phasor rotation needed to correct known offset ~ associated voltage signal (for current signals only) ~ text data for generating signal name (might include sensor model & firmware version)It is acceptable to embed the configuratin file within the data header, if any.16D. Item 1.5.1 should have an additional bullet specifying a processing log to accompany data which have been changed from those initially recorded. Such changes might include filtering, resampling, calculation of derived quantities, renaming or selective deletion of signals.[143] Integrated Monitor Facilities for the Eastern Interconnection: Management & Analysis of WAMS Data Following a Major System Event, J. F. Hauer. Working Note of the Eastern Interconnection Phasor Project (EIPP), December 16, 2004.
Response: The SDT thanks you for your comments and appreciates the level of detail in your concerns. The SDT chose to retain the existing proposed standard text in these areas. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Progress Energy Carolina, Inc.	Yes	R6.2 requires "16 samples per cycle"R9.2 requires "960 samples per second "SDT should pick a common way to state sample rate.
Response: Thank you for your comment. The SDT considered the comment but left the proposed standard wording unchanged in this regard. The draft standard was modified to revise the requirement to store calculated electrical quantities at a rate of at least 30 times per second. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second”. The 960 samples per second requirement presently exist in PRC-002-1.		
Hydro-Québec TransEnergie (HQT)	Yes	1. Regarding Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data, as we commented in Question 5 and elsewhere performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. We do not feel that the 200kV threshold, nor the plant/plants' capacities are appropriate criteria for assessing criticality. This should be reflected in the table. 2. The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities greater than 1500MVA. As we commented in Question 5 and elsewhere we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications.

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. 1. Table 2-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses. 2. The standard has been revised to eliminate voltage level and generation size from the applicability section.		
Entergy Services, Inc	Yes	Seems like Section D.1.5 Additional Compliance Information should be listed as part of the requirements.
Response: Thank you for your comment. The SDT considered this it but decided to leave these items in the compliance sections. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Northeast Utilities	Yes	The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities greater than 1500MVA. As commented in Question 4, the 200kV threshold is an not an appropriate criteria for assessing criticality.
Response: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		
San Diego Gas and Electric Co.	Yes	How would this standard apply to a typical combined cycle plant where the total capability of the plant is above 500MVA, but each of the individual generators is not?
Response: Thank you for your comment. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus.		
New York Independent System Operator	Yes	(D1.5) The bullet items covering COMTRADE and COMNAMES seem to us to be ?Requirements, and it seems odd to find these items under ?Compliance Information. We suggest that, if these items remain in this position, there should be a corresponding Requirement.D.1.5 Common DDR files can be converted into COMTRADE and the purpose stated in COMTRADE for this conversion to a common format is that conversion ?is necessary to facilitate the exchange of such data between applications.? D.1.5 The drafting team should be aware of several IEEE PSRC activities which are in process now, and will affect items covered in this Standard. These activities include the following:C37.111 COMTRADE revision Working Group H4C37.118

Organization	Yes or No	Question 16 Comment
		Synchrophasor Standard revision Working Group H11Channel Names and Instrument Names Working Group H10SOE Data Working Groups H5b (completed) and H16
Response: The SDT thanks you for these comments. The SDT chose to retain these in the compliance section. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Tucson Electric Power	Yes	Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement. The standard drafting team did not move the data format requirements into the Requirements section of the standard because the standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard.		
Duke Energy	Yes	Key Issue #6 listed on page 3 of the Comment Form states that compliance elements (VRFs, VSL, etc.) will be included in a later version of the standard. We strongly encourage the drafting team to include these in the next version issued for comments, because the inclusion of these elements is needed to refine the Requirements.
Response: Thank you for your comment. The SDT plans to include these compliance elements in the second formal posting of the proposed standard.		
CenterPoint Energy	Yes	1. This draft standard includes ambiguities, such as the time stamp for the SOE data for the change in circuit breaker position (open/close) for each circuit breaker in a substation?. Requirement 3 indicates the time stamp shall be recorded ?to within four milliseconds of input received for the change in circuit breaker position (open/close) for each of its circuit breakers specified in Requirements R1 and R2?. It is questionable of what is

Organization	Yes or No	Question 16 Comment
		meant by within four milliseconds of input received for the change in circuit breaker position. For example, is this referring to monitoring of a circuit breaker 52a or 52b auxiliary contact or is something else intended such as circuit breaker main contact parting or closing (when load or fault current begins and ends). 2. The compliance section includes several items that appear to be requirements, but are shown in the compliance section instead of in the requirements section. For example, all the data must be in a format in which COMTRADE software can be used to evaluate the data. As another example, item D.1.5.1 states All known delays in interposing relays shall be reported along with the SOE data?. It is unnecessary and excessive to require such reporting of time delays that are insignificant and should already be taken into account within the accuracy specification. CenterPoint Energy recommends removing items for the Compliance section that are truly requirements. Each item removed should be evaluated before including it as a requirement in this proposed standard. 3. While previously referenced in response to Question 13, CenterPoint Energy is concerned this proposed standard does not sufficiently take into consideration common natural disaster situations. The FERC-approved NERC reliability standard FAC-003 for Vegetation Management does include allowances for situations resulting from natural disasters, such as tornados and hurricanes. This proposed standard does not address the enormous quantities of data and associated complications that arise in such situations. CenterPoint Energy recommends reviewing the various requirements and including appropriate allowances to address the expected operational issues that are encountered during and after natural disasters.
Response: Thank you for your comment. 1. This requirement is intended to monitor a circuit breaker 52a or 52b contact. The intent is for the SOE device to record the change of state within 4 milliseconds of this change of state. 2. The SDT considered this comment but decided to retain the items in the compliance section in the revised standard, except that the interposing relay delay reporting has been eliminated. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 3. Please see the response in question 13.		
Xcel Energy	Yes	All of the items in section 1.5 "Additional Compliance Information" of the Compliance section appear to be requirements. These are adding to the requirements in the standard and are not appropriate in this section. If the SDT feels these should be required (by virtue of using "shall"), then a new draft should be developed to include these as actual requirements of the standard. Additionally, the new draft should be posted for another comment period.
Response: Thank you for your comment. The SDT considered this comment and determined that the proposed standard will retain these compliance elements. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		

Organization	Yes or No	Question 16 Comment
Utility System Efficiencies, Inc.	Yes	1. Would this standard apply to a combined cycle plant where the total capability was above 500 MW (and less than 1500 MW) but each of the individual units were not greater than 500 MW. 2. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. I suggest allowing DST files as are used by entities within WECC. 3. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.16C. Item 1.5.1 should have an additional bullet on configuration files:? All reported DDR data shall be accompanied by a configuration file (CF) providing the following primary information: - the data source to which the CF applies (name of the archiving device) - structure of the data source records (number of sensors, sensor names, number of signals for each sensor) - parameters for each signal: ~ sensor producing the signal (includes sensor model & firmware version) ~ signal type (voltage, current, other) ~ scale factors for conversion to engineering units ~ timing shift or phasor rotation needed to correct known offset ~ associated voltage signal (for current signals only) ~ text data for generating signal name (might include sensor model & firmware version)It is acceptable to embed the configuration file within the data header, if any.16D. Item 1.5.1 should have an additional bullet specifying a processing log to accompany data which have been changed from those initially recorded. Such changes might include filtering, resampling, calculation of derived quantities, renaming or selective deletion of signals.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
British Columbia Transmission Corporation	Yes	1. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. 2. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response: Thank you for your comment. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a		

Organization	Yes or No	Question 16 Comment
direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Kansas City Power & Light	Yes	1. Section 1.3.2 and section 1.5 are in the format of requirements of response times and data format expectations. This is unusual for the Data Retention section. Normally the Data Retention section is targeted to the time required to retain information to demonstrate compliance. It is possible the data format expectations could be in the compliance section. Request the SDT consider whether these are more in line as requirements rather than data retention. 2. Believe there is a potential error in the Effective Date in Section A, item 5, Effective Date. The first sentence states for requirements R1 - R11 must be 50% compliant four years after approval of NERC or FERC, whichever applies. Should this be two years?
Response: Thank you for your comment. 1. The SDT considered this comment and decided to retain these compliance requirements. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 2. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
MRO NERC Standards Review Subcommittee	Yes	
Bonneville Power Administration	Yes	
Alberta Electric System Operator	Yes	
Dominion		The applicability section of this draft standard is not consistent with NERC's Statement of Compliance Registry Criteria for a TO and GO (i.e., individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher).NERC's Statement of Compliance Registry Criteria states: If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated [emphasis added] to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations.? We therefore recommend that the language referring to voltage and size be removed from the applicability portion of the standard and instead be applied to the requirements within the standard.
Response: Thank you for your comment. The proposed standard has been revised in accordance with your comments.		

Organization	Yes or No	Question 16 Comment
Salt River Project		
WECC		
Brazos Electric Power Cooperative, Inc.		
E.ON U.S.		
National Grid		
Grant County PUD		

General Questions

17. Do you agree with the implementation plan as proposed by the SDT? If no, provide a plan that would be acceptable to you and provide rationale.

Summary Consideration: The implementation plan in the revised standard has been modified, and the wording of the percentage of compliance milestones has been clarified.

If older GPS equipment has accuracy problems, it will need to be replaced to meet compliance.

Disturbance data shall be stored for a minimum of 10 calendar days following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).

Organization	Yes or No	Question 17 Comment
Northeast Power Coordinating Council	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:?" For consistency the latter should be changed to four years after Board of Trustees adoption. As written, the timelines are not only inconsistent, but two years is too aggressive a time frame for what is required, in particular considering that Board of Trustees adoption precedes regulatory approval.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one in the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
IRC Standards Review Committee	No	The Implementation schedule for R1 - R11 is not clear. It seems as if a logical schedule would be that all entities be 50% compliant within 2 years and 100% compliant within 4 years. Yet as written it seems to obligate non-regulated entities to be compliant within 2 years while regulated entities have 4 years. Similarly for R12 & R13, the schedule gives regulated entities 18 months to comply but only 3 months for non-regulated entities.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one in the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		

Organization	Yes or No	Question 17 Comment
Bonneville Power Administration	No	It's too fast for a 3 year budget cycle entity.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Florida Power & Light	No	1. From an audit standpoint the statement Each Responsible Entity shall be at least 50% compliant on monitored equipment would seem to be very difficult standard to meet or defend during on audit. Perhaps a better yardstick could be developed for improved audit ability. The overall four year requirement for 100% compliance and 50% compliance in 2 years will place an extremely high burden on many companies especially with nuclear assets. Two years is not enough time to budget design and install a DME into a nuclear facility. How can 50% compliance be met in two years? As seen in the last two years, most manufacturers are unable to keep up with industry demand. Therefore, the ability of the DME manufactures to meet the manufacture volume requirements is also unknown. Six years overall time frame is much more realistic for an implementation plan. 2. GPS equipment synchronization is possible for all existing DMEs that I am aware of; however, some testing indicates that not all equipment can internally use this signal and actually time stamp to the required accuracy. Perhaps for older equipment, the requirement for accurate GPS time synchronization would be sufficient for the purpose of this standard. Older equipment should be allowed to be used during the transitional period without risk of an audit finding for not meeting a +2 millisecond time accuracy requirement. If you have equipment that cannot meet the +_ 2 millisecond requirement, this may result in an unintended consequence that will force companies to remove equipment from their DME list. 3. Older DME equipment do not provide for long term storage. Requiring retrieval or local storage is only possible if the need for data is known soon enough to download and store locally. This would put almost everyone at risk for an audit finding for missing data. One of the primary reasons for replacing DMEs may be due to the 10 day retrieve ability requirement. It seems that timing of this requirement puts the cart before the horse and would seem entirely unrealistic to implement this requirement before the equipment is in place to provide the storage function. Again, if you have equipment that cannot meet the +_ 2 millisecond requirement, this may result in an unintended consequence that will force companies to remove equipment from their DME list.
Response: Thank you for your comment. 1. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.2. The time accuracy requirement is deemed necessary as a technical requirement to provide data that is adequate for wide area disturbance event		

Organization	Yes or No	Question 17 Comment
analysis. 3. The less aggressive implementation plan should aid in meeting the storage function.		
US Bureau of Reclamation	No	As I have mentioned in tems 2 & 5 above, generator capacities (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbance analysis. These values should be 20MVA/unit and 75MVA/plant.
Response: Thank you for your comment. Please see the responses for question 5 above.		
NERC	No	Effective Date R12-R13For consistency, the first bullet under Effective Dates should read:The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Tri-State Generation and Transmission Association	No	Effective dates for 50% and 100% compliance are given. The dates are the same unless no regulatory approval is required. Should the date for 50% compliance be two years after the "applicable Regulatory Approval" instead of also four years?
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
NextEra Energy Resources (formerly FPL Energy)	No	The phased-in approach presented in the Implementation Plan for compliance seem to be unnecessarily restrictive. Issues such as obtaining outages, acquisition of equipment, &/or obtaining personnel necessary to install/replace recording equipment can be difficult and time consuming. It is recommended that rather than the phased-in approach, set a timeframe for completion at a more reasonable five (5) year level regardless of whether there is existing equipment or not.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to		

Organization	Yes or No	Question 17 Comment
ensure a realistic transition to the new requirements.		
Exelon Generation LLC	No	1. Effective date: What does 50% compliant means for a registered Generation Owner (GO) like Exelon that has multiple sites with each site consisting of a single or multiple units? In our case, some units may require DDRs while others may not. Does 50% compliance within two years means 50% of the units in the fleet have to be compliant within two years or does 50% compliant within two years means 50% of the required parameters/quantities to be monitored should be available within two years? We are trying to understand for Generation Owners, does 50% compliance apply to a unit or to a site or to registered GO as a whole? Please clarify. 2. Effective date: PRC-018-1 had a Requirement of 75% compliant within 3 years. Has that Requirement been dropped by PRC-002-2? 3. Effective date: Requirement R12 and R13 This needs to be clarified that these effective dates are applicable to the already installed DME equipment for which GO/TO is taking or intends to take credit for meeting the requirements of this standard. These dates are not applicable to the new equipment. New equipment is allowed to be installed within 2 to 4 years of Regulatory approval. So installing synchronizing capability within 18 months of Regulatory approval, when equipment is not even installed yet, does not make sense.
Response: Thank you for your comment. 1. . Data for required parameters/quantities for 50% of the designated locations to be monitored should be available within two years. 2. PRC-018 will be replaced by the proposed standard. The 75% requirement has been dropped by PRC-002-2. 3. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
DTE Energy/Detroit Edison	No	DME installation at generating stations are dependent on outage schedules. Suggest increasing compliance requirements to 50% at three years and 100% at five years.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
ITC Transmission, METC	No	In the effective dates for Requirements R1 through R11, the Item 1. time frame of "four years" contradicts the Item 2. time frame "two years".
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation		

Organization	Yes or No	Question 17 Comment
plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Progress Energy Carolina, Inc.	No	Some region requirements developed under current PRC-002-1 are closer to where NERC is moving than with other regions. Current PRC-018-1 is underway with TO & GO implementation to meet those region requirements today. For PEC, May 2009 is the first 50% effective date per PRC-018-1. PEC believes that under these circumstances that NERC should address this unique situation now and not wait until PRC-002-2 approval. Compliance related to PRC-018-1 should be deferred until approval of PRC-002-2.
Response: Thank you for your comment. PRC-018 will remain in effect until the adoption of this standard. The SDT is not aware of plans to defer PRC-018 compliance.		
Hydro-Québec TransEnergie (HQT)	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:?" For consistency the latter should be changed to four years after Board of Trustees adoption. As written, the timelines are not only inconsistent, but two years is too aggressive a time frame for what is required, in particular considering that Board of Trustees adoption precedes regulatory approval.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Northeast Utilities	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:?" Two years versus four years is inconsistent.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.

Organization	Yes or No	Question 17 Comment
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Xcel Energy	No	Paragraph 1 of the Implementation Plan appears to be written incorrectly. It says that 50% of R1 - R11 have to be completed in 4 years for following regulatory approval but within 2 years after BOT approval where regulatory approval is not required. Paragraph 2 then says that 100% of R1 - R11 has to be completed in 4 years. We assume the intent is for 50% of R1-R11 to be completed in 2 years, following regulatory approval, not 4 years.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
SERC Protection and Controls Sub-committee	Yes	There appears to be a typo on the first bullet under Requirements R5.1 "Effective Date" four years should be two years. Also a typo under Requirements R12 and R13 where "eighteen months" was left out in the second part of the sentence. This needs to be clarified.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PacifiCorp	Yes	The time allowed in the draft standard appears acceptable.
Response: The SDT thanks you for your comment.		
Dominion	Yes	We suggest revising the language in section 5 first bullet for R1 through R11 to read: The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required each Responsible Entity shall be at least 50% compliant within two years

Organization	Yes or No	Question 17 Comment
		and 100% compliant within four years. Correct a typo error on the first bullet under requirement R5.1 Effective Date four years should be two years. Correct an omission error under Requirements R12 and R13 where eighteen months was left out in the second part of the sentence.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
FirstEnergy	Yes	Although we agree with the implementation plan, there seems to be a typographical error in the 1st bullet under the "Effective Date" section 5 of the standard: "four years" should be changed to "two years".
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Cowlitz County PUD	Yes	Question 17 Comments: This standard as written will not apply to Cowlitz and therefore will not present a burden.
Response: The SDT thanks you for your comment.		
SPP System Protection and Control Working Group	Yes	1) Please clarify the effective dates section stating when each entity needs to be 50% and 100% compliant respectively.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Duke Energy	Yes	Regarding the effective dates for Requirements R1 through R11, we question the effective date for 50% compliance - shouldn't it be something less than four years? Four years is the timeframe for 100% compliance.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		

Organization	Yes or No	Question 17 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NV Energy	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Entergy Services, Inc	Yes	
Progress Energy Florida	Yes	
San Diego Gas and Electric Co.	Yes	
Grant County PUD	Yes	
Schneider Electric	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Manitoba Hydro	Yes	
NYISO	Yes	
JEA	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 17 Comment
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
Members of the WECC Disturbance Monitoring Work Group		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PG&E System Protection		The Effective date information is unclear for the 50% and 100% compliance requirements. Also, how would this implementation plan affect the PRC-018 application?
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements. This standard will replace PRC-018 when adopted.		
Portland General Electric		The following comments are those filed by the DMWG which we are filing in support: The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Puget Sound Energy		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Tucson Electric Power		The Effective date information is unclear for the 50% and 100% compliance requirements.

Organization	Yes or No	Question 17 Comment
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Utility System Efficiencies, Inc.		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PNM		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Wisconsin Electric		
New York Independent System Operator		
Brazos Electric Power Cooperative, Inc.		
E.ON U.S.		
TransAlta		
Arizona Public Service Co.		
WECC		
CenterPoint Energy		
Pacific Northwest National Laboratory		

Organization	Yes or No	Question 17 Comment
Salt River Project		
National Grid		
Los Angeles Department of Water & Power		
British Columbia Transmission Corporation		

General Questions

18. The standard is proposing a definition for "Substation" based on the IEEE definition. Do you agree that there is sufficient misunderstanding of this term to warrant a definition? If so, do you agree that the IEEE definition is the most appropriate definition?

Summary Consideration: Comments indicate that there is sufficient misunderstanding of the term "Substation" to warrant a definition; however, as several comments pointed out, the IEEE definition of Substation includes a transformer and therefore eliminates what the industry commonly refers to as "switching stations." Because of this, the drafting team agrees that the IEEE definition of Substation is not acceptable for use in this standard.

The drafting team has made significant changes to the standard based on comments received. The new location criteria are based on short circuit levels and eliminate the word "Substation" from the standard.

Organization	Yes or No	Question 18 Comment
Alberta Electric System Operator	No	
Response:		
Duke Energy	No	We agree with the IEEE definition. We don't think that there is sufficient misunderstanding to warrant a NERC definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
IRC Standards Review Committee	No	
Response:		
SERC Engineering Committee Planning Standards Subcommittee	No	There is not sufficient misunderstanding to warrant a definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		

Organization	Yes or No	Question 18 Comment
Dominion	No	We do not believe that a definition is warranted. However, if one is deemed necessary we agree with the use of the IEEE definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
Florida Power & Light	No	The terms substation and "Aggregate plant total nameplate" for the purpose of this standard should be well defined due to the compliance/audit issues that a misunderstanding of these terms could bring for a TO and/or GO.
Response: Thank you for your comment. The Standard has been modified to hopefully clarify the location requirement with out using the term "Substation."		
US Bureau of Reclamation	No	This document should be clarified the meaning of "Interconnected System." Is it connection of TO and GO system? Is it junction point of Main-transmission system and sub-transmission system? Etc.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation." "Interconnected systems" of the TO and GO or multiple TOs will need to have appropriate agreements of responsibility for compliance to the standard requirements, but this is beyond the scope of this standard.		
Progress Energy Florida	No	Clarification is needed whether to include switching stations as part of the criteria (i.e., will a 230kV facility with 5 - 230kV transmission lines without a transformer require a DFR?) Many interpret that a substation includes transformation otherwise the station is a switching station. .
Response: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these "Switching Substations." The standard has been modified to clarify the location requirement without using the term "Substation."		
Bonneville Power Administration	Yes	Also supply the IEEC C37.111-1999 and C37.232-2007 referred to.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
SERC Protection and Controls Sub-committee	Yes	We agree with the IEEE definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		

Organization	Yes or No	Question 18 Comment
American Electric Power	Yes	Yes, AEP agrees that there is sufficient misunderstanding. No, AEP does not agree that the IEEE definition is the most appropriate. The portion 'enclosed assemblage' is not clear enough to distinguish assets applicable to the standard. For example, distinct and separate busses, of differing voltage, that may be enclosed by a common fence.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
Manitoba Hydro	Yes	We agree with the IEEE definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
DTE Energy/Detroit Edison	Yes	A definition is warranted, but the IEEE definition doesn't cover all the configurations that exist.
Response: Thank you for your comment. The Standard has been modified to hopefully clarify the location requirement without using the term "Substation."		
ITC Transmission, METC	Yes	The definition does not work with the standard. There are station facilities with multiple switchyards that are not connected locally. This may cause inaccuracies when counting number of lines for a substation.
Response: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these "Switching Substations." The standard has been modified to clarify the location requirement without using the term "Substation."		
Hydro-Québec TransEnergie (HQT)	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modfiying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these "Switching Substations." The standard has been modified to clarify the location requirement without using the term "Substation."		
Northeast Utilities	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as

Organization	Yes or No	Question 18 Comment
		generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modfiying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these “Switching Substations.” The standard has been modified to clarify the location requirement without using the term “Substation.”		
Tri-State Generation and Transmission Association	Yes	Some definitions of substation require a transformer so the IEEE definition includes what might be considered a switchyard as well as of a substation.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
Southern Company - Transmission	Yes	Southern Company supports the proposed definition of "Substation."
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
Northeast Power Coordinating Council	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modifying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these “Switching Substations.” The standard has been modified to clarify the location requirement without using the term “Substation.”		
Los Angeles Department of Water & Power	Yes	
Grant County PUD	Yes	

Organization	Yes or No	Question 18 Comment
SPP System Protection and Control Working Group	Yes	
NYISO	Yes	
FirstEnergy	Yes	
NERC	Yes	
Cowlitz County PUD	Yes	
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
PacifiCorp	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Exelon Generation LLC	Yes	
Wisconsin Electric	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 18 Comment
Progress Energy Carolina, Inc.	Yes	
City of Tallahassee (TAL)	Yes	
Entergy Services, Inc	Yes	
Kansas City Power & Light	Yes	
JEA	Yes	
New York Independent System Operator	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
Xcel Energy		We agree the IEEE definition is appropriate.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
TransAlta		
National Grid		
Tucson Electric Power		
CenterPoint Energy		
PG&E System Protection		

Organization	Yes or No	Question 18 Comment
Puget Sound Energy		
Portland General Electric		
Salt River Project		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Pacific Northwest National Laboratory		
San Diego Gas and Electric Co.		
E.ON U.S.		
Arizona Public Service Co.		
NV Energy (fka Sierra Pacific Resources)		
WECC		
Members of the WECC Disturbance Monitoring Work Group		