Consideration of Comments

Project 2007-11 Disturbance Monitoring

The Disturbance Monitoring Drafting Team thanks all commenters who submitted comments on the Standard Authorization Request (SAR). These standards were posted for a 45-day public comment period from May 9, 2014 through June 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 67 sets of comments, including comments from approximately 173 different people from approximately 111 companies representing all 10 Industry Segments as shown in the table on the following pages.

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

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

Overall Summary Consideration:

While most stakeholders agreed with the merging of the notification requirement of Requirement R2 into Requirement R1, many have voiced their concerns for various technical hurdles in adhering to the specific methodology prescribed in Attachment 1. However, it is crucial to remember the primary intent of the requirements is that the standard is designed to address "what" data is needed, not "how" it is captured. Further, industry experts continue to emphasize that "why" an event occurred is equally, if not more, valuable than "what" happened. In this sense, as long as the quantities (data) can be determined, the intent of the requirements are satisfied.

Many stakeholders were unhappy with the bulleted list in Requirement R5, Part 5.1.2, either with a single bullet or with the list altogether. The standard drafting team revised Requirement R5, Part, 5.1.2 and removed the bulleted list of "or" statements, replacing it with "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."

In Requirement R5, the use of "BES buses" was found to be confusing by many stakeholders. The use of this language was simply to provide clarity but, in response to industry's comments, the drafting team revised R5 by removing "BES buses". The Requirement now references only BES Elements.

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

A number of stakeholders voiced their concerns for more precise wording of the Step 7 in Attachment 1 which stated "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA." The ambiguity arose out of the term "buses" because it could be read as requiring FR and SER data from more than one bus. Thus, Step 7 is now revised to read "If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA."

Several stakeholders also commented that Requirement R11 had no substantial impact on improving the reliability of the system. The DMSDT notes that the Requirement R11 ensures data availability from the data sources, timely retrievability of the data and common format so that the data can be read and used in the expeditious and effective analysis of events. Requirement R11 provides a reliability impact by integrating all of the previous requirements in the standard with respect to data reporting facilitate event analysis. The first two Parts of Requirement R11 specify how long an entity has to provide requested data (Part 11.1) and also limits how long data must be retained by the TO or GO (Part 11.2). Parts 11.3-11.5 ensure the uniformity and consistency of the data that is reported.

One technical change many stakeholders proposed was to revise Requirement R10 to relate to time synchronization of the device clock rather than data. The Requirement's original language called for time synchronization of SER data within +/- 2 milliseconds. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data. The drafting team revised Requirement R10 accordingly.

Based on stakeholder feedback, the DMSDT capitalized the defined terms System, Transmission and Disturbance. The DMSDT believes that this adds clarity regarding the requirements and rationales in PRC-002-2. In some instances, these terms appear adjacent to each other within sentences of Requirements, Rationales or Guidelines. The following instances occur:

- Transmission System
- System Disturbance
- System Demand

The DMSDT has also incorporated the defined term "Transmission Line". The DMSDT does not intend to create any new defined terms by the above uses. Each defined term stands on its own.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	SERC	1, 3, 5, 6
2.	Louis Slade	NERC Compliance Policy	RFC	1, 3, 5, 6
3.	Randi Heise	NERC Compliance Policy	MRO	1, 3, 5, 6
4.	Chip Humphrey	Power Generation Compliance	RFC	5
5.	Jeff Bailey	Nuclear Compliance	NPCC	5
6.	Larry Nash	Electric Transmission Compliance	SERC	1, 3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10

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

2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Peter Yost	Consolidated Edison Co, of New York, Inc.	NPCC	3
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Wayne Sipperly	New York Power Authority	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jared Shakespeare	Peak Reliability	X									

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X		X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6

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

7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

5.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

N/A

6.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

7.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

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

8.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5

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

5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			RFC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Clancy	Cleco Power	SPP	1, 3, 5, 6
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
3.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Mike Kidwell	Empire Electric District	SPP	1, 3, 5
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
10.	Frankie Smith	Kansas City Power & Light	SPP	1, 3, 5, 6
11.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	David Greene	SERC Protection and Controls Subcommitee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Greg Davis	Georgia Transmission Corporation		
3.	Bridget Coffman	Santee Cooper		
4.	Charlie Fink	Entergy		
5.	David Greene	SERC		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Group	Thomas McElhinney	JEA	X		X		X					

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Greg Campoli	ISO RTO Council Standards Review Commitee		X								

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

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Authority	FRCC	3
7.	Don Cuevas	Beaches Energy Services	FRCC	1

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

8. Stanley Rzad	Keys Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Brian Van Gheem	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3. Allan George	Sunflower Electric Power Corporation	SPP	1
4. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
5. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6. John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Richard Hoag	FirstEnergy	X		X	X	X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Michael Lowman	Duke Energy	X		X		X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Regulated Marketing	RFC	5
4. David Szulczewski	SEE	RFC	

No.	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
	5. Karie Barczak	NERC Compliance	RFC										
20.	Group	Erika Doot	Bureau of Reclamation	X				X					
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
	1. Richard T Jackson												
	2. Shawn Patterson												
21.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
N/A													
22.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
	1. Jim Burns	Technical Operations	WECC	1									
23.	Individual	David Jendras	Ameren	X		X		X	X				
24.	Individual	Leonard Kula	Independent Electricity System Operator		X								
25.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
26.	Individual	Tracy Richardson	Springfield Utility Board			X							
27.	Individual	John Allen	City Utilities of Springfield, MO	X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co			X	X	X					
30.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
31.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
32.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
33.	Individual	Scott Langston	City of Tallahassee	X									
34.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
35.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Karen Webb	City of Tallahassee					X					
37.	Individual	Alshare Hughes	Luminant Generation Company, LLC	X		X		X					
38.	Individual	Dan Roethemeyer	Dynegy					X					
39.	Individual	Michael Moltane	ITC	X									
40.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
41.	Individual	John Brockhan	CenterPoint Energy Houston Electric, LLC	X									
42.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
43.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
44.	Individual	Oliver Burke	Entergy Services, Inc.	X									
45.	Individual	Bill Fowler	City of Tallahassee			X							
46.	Individual	Don Schmit	Nebraska Pubilic Power District	X		X		X					
47.	Individual	John Pearson	ISO New England		X								
48.	Individual	Karin Schweitzer	Texas Reliability Entity										X
49.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
50.	Individual	Anthony Jablonski	ReliabilityFirst										X
51.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
52.	Individual	Jonathan Meyer	Idaho Power Co.	X									
53.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
54.	Individual	Bill Temple	Northeast Utilities	X									
55.	Individual	David Kiguel	n/a								X		
56.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				
57.	Individual	Catherine Wesley	PJM Interconnection		X								
58.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
59.	Individual	Thomas Standifur	Austin Energy	X		X		X	X				
60.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
61.	Individual	Venona Greaff	Occidental Chemical Corporation							X			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
62.	Individual	Dianne Gordon	Puget Sound Energy	X		X		X					
63.	Individual	Heather Rosentrater	Avista Utilities	X		X		X					
64.	Individual	Glenn Pressler	CPS Energy	X		X		X					
65.	Individual	Daniel Duff	Liberty Electric Power, LLC					X					
66.	Individual	Laurie Williams	PNM	X		X							
67.	Individual	D Mason	HHWP					X					

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

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	We agree with the comments submitted by SERC PCS.
ISO New England	Agree	ISO RTO Council Standards Review Committee (SRC)
Illinois Municipal Electric Agency	Agree	Florida Municipal Power Agency, and PJM
Luminant Energy Company LLC	Agree	Luminant Generating Company LLC
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **The DMSDT merged the notification requirement of Requirement R2 into Requirement R1. The DMSDT also merged the notification requirement of Requirement R7 into Requirement R6 (new R5). Do you support these new requirements? If not, please explain why and provide suggested changes.**

Summary Consideration: While most stakeholders agreed with the merging of the notification requirement of Requirement R2 into Requirement R1, many have voiced their concerns for various technical hurdles in adhering to the specific methodology prescribed in Attachment 1. However, it is crucial to remember that the primary intent of the standard's requirements is that they are designed to capture "what" data is recorded, not "how" it is recorded. Further, industry experts continue to emphasize that "why" an event occurred is equally, if not more valuable than "what" happened. In this sense, as long as the quantities (data) can be recorded or determined, the intent of the requirements are satisfied.

Organization	Yes or No	Question 1 Comment
Peak Reliability	No	The initial list of locations should come from the owners (TOs and GOs) with a subsequent review process as identified by the Responsible Entity. The Responsible Entity should have the authority to require additions as it sees necessary. Owners should provide the initial list because they have access to the information and would bear the cost of installing DDRs.
Response: FR and SER locations are determined by the Transmission Owners. The DMSDT has assigned the responsibility for DDR data locations to the Responsible Entity (Peak Reliability in WECC) because DDR data is reflective of a wide area System response and it is appropriate for the Responsible Entity to identify what BES Elements data is needed for. It is the responsibility of the RC in WECC to develop the list, but development of the DDR list can be done collaboratively through WECC committees. An initial list has already been prepared by WECC JSIS, whose members are primarily operating entities. The Responsible Entity can add or remove locations from this list per Requirement R5 for DDR data. The DMSDT considered FR and SER data as primarily localized information, with the TO being better suited to make the selections.		
ISO RTO Council Standards Review Committee	No	We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. Please see the DMSDT response to your comments to Question 2.		
Seattle City Light	No	R1 does not meet NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify buses, (2) notify others of buses, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends rewriting R1 to include three subrequirements as follows: R1. Each Transmission Owner shall: R1.1 Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. R1.2 Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data. R1.3 Reevaluate the identified BES buses at least once every five calendar years. In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of buses for which monitoring now would be required. Seattle suggests that an implementation period be identified for installing SER and FR equipment for newly identified buses similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Response: The Drafting Team has revised Requirement R1 as per your comments. **The Implementation Plan addresses data recording capability for newly-identified buses and BES Elements--"Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." This language was added to Part 1.3 of the revised Requirement R1 in the standard for clarity. The Rationale Boxes for Requirements R1 and R5 explain the reevaluation interval: newly identified BES buses and BES Elements are identified at the five-year reassessment. The implementation of the reassessed list will be as per the Implementation Plan.**		

Organization	Yes or No	Question 1 Comment
As the standard is written, newly constructed BES buses or Elements are handled via the reevaluation of the identified BES buses, not individually as they are brought online.		
Florida Municipal Power Agency	No	see question 3
Response: Thank you for your comment. Please see the DMSDT responses to your comments under Question 3.		
ACES Standards Collaborators	No	We concur with the SDT's observation and rationale that "the requirement for DDR data for identified BES Elements...is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We feel that industry is not only capable of identifying the number of devices from this experience, but also where these devices should be located for dynamic disturbance recording, sequence of events recording, and fault recording purposes. We believe this standard should require an entity to generate its own methodology to make these determinations and how often. We feel the method proposed for selecting BES Elements is too broad and could be subject to interpretation from auditors when not properly followed. We also have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the implementation plan and based on the effective date of the standard.
Response: The Standard Drafting Team, after extensive outreach to industry experts related to event analysis and Disturbance Monitoring, identified BES Elements that, if covered by disturbance recording, would significantly contribute to effective, efficient and accurate analysis. Industry experts continue to highlight that "why" an event occurred is equally valuable, if not more valuable, than "what" happened. Even with the proliferation of DDR, defining critical BES Elements requiring monitoring ensures adequate data is available for event analysis purposes. The DMSDT has outlined these BES Elements in Requirement R5, selecting		

Organization	Yes or No	Question 1 Comment
the minimum set of Elements necessary for this analysis. Allowing entities to develop their own methodology could lead to inconsistency and uncertainty in capturing the data necessary for event analysis purposes. It must be emphasized that an entity will not be notified that it has to install recording devices. An entity will only be notified that it has to have the data for what it has been notified for. The Responsible Entity develops a list of BES Elements for which DDR data is required. That list is provided to the TOs and GOs of their respectively owned Elements. The TOs and GOs are then required to provide that DDR monitoring capability, as per the Implementation Plan. The Implementation Plan regarding the TOs and GOs required to provide DDR monitoring capability, states: "Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: • Entities shall be at least 50 percent compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date. • Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date. Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." This addresses the transition period for the TOs and GOs to implement necessary monitoring for both the initial list developed and subsequent reassessments. The DMSDT also revised Requirement R1 to clarify the implementation of the reevaluated list. "1.3. Reevaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan."		
Bureau of Reclamation	No	The Bureau of Reclamation suggests that the phrase "may require" in R1 and R5 should be changed to "require." Once an element is identified as requiring data in R1 or R5, R2-R4 and R6-R10 require data collection without exception, so the phrase "may require" could create confusion.
Response: The wording in Requirements R1 and R5 was revised, and "may" was removed from the requirement.		
Bonneville Power Administration	No	BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance

Organization	Yes or No	Question 1 Comment
		responsibility. BPA also believes that other TOs (in order to determine their own compliance responsibility) should use the same fault MVA data to determine busses to which they have elements connected. BPA feels this requirement, as written, places an undue compliance risk on TOs.
Response: There are BES buses connected to BES Elements owned by different entities. The studies done by the different owners to identify monitored BES buses could yield different results for what needs to be monitored; which necessitates the notification from one Transmission Owner to another.		
Independent Electricity System Operator	No	We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
Response: Thank you the comment. Refer to the DMSDT response to your comment in Question 2.		
City Utilities of Springfield, MO	No	We support the merging of R2 into R1 and R7 into new R5. However, we do not support R1 Attachment 1 methodology regarding identifying BES buses for locating SER & FR devices to capture SER & FR data. See comments in question #3 for our reasoning.
Response: Thank you for your comment. Refer to the DMSDT response to your comment to Question 3.		
American Electric Power	No	R1: The scope for the process in Attachment 1 should be limited to only those BES buses that have local protection systems that serve to protect the connected BES elements. R1: The process for identifying BES buses within Attachment 1 could lead to a breaker protected load bus, with only two BES source lines, being in the "top 10%" of locations that must have DFR/SER. The reason for such a location being in the top 10% would be driven by its proximity to other top 10% BES buses. The Standard should allow for exclusion of such locations, provided they are substituted by the next BES bus in the list. AEP believes this change would allow DFR/SER equipment to be deployed where proper

Organization	Yes or No	Question 1 Comment
		event analysis is truly needed. An alternate approach would be to completely eliminate the top 10% criteria, which would allow industry maximum flexibility in determining the most appropriate location for such installations. R1 & R5: As written, these requirements are single sentences which are five lines in length. With no transitions of thought, they are difficult to read. The wording should be revised to break up independent thoughts so it reads more concisely. R1 & R5: The notification within 90 calendar days has no reference point. The requirements should be revised to state "... within 90 days of completing the Attachment 1 methodology" or similar wording. R1 & R5: Both requirements state "BES Elements may require..." Why is this a "may" statement? This seems to be in conflict with the beginning statement of the requirement that indicates a bright line identification of what requires monitoring. AEP recommends employing a consistent structure for R1 and R5. The criteria for R1 are contained within an appendix, while the criteria for R5 are contained within the requirement. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element.
Response: **The DMSDT notes that Requirement R1 specifies BES buses/Elements where FR and SER data (not equipment) is required to be captured. The data itself is specified in Requirement R3 which states "Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each of the BES Elements it owns connected to the BES buses identified**		

Organization	Yes or No	Question 1 Comment
in Requirement R1:" As long as the quantities (data) can be determined, the intent of the requirements are met. This standard identifies minimum data requirements. The DMSDT has revised Requirements R1 and R5 for clarity. The DMSDT agrees and has revised the wording to include "… within 90 calendar days of completion of Part 1.1…" and "…within 90 calendar days of completion of Part 5.1…" The DMSDT agrees and has revised the wording to remove "may" from both requirements. The DMSDT notes that Attachment 1 contains a procedure, while Requirement R5 contains bright line criteria for DDR data. It does not matter at which terminal data is captured, as long as the required data can be determined.		
City of Tallahassee	No	see response for question 3
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Kansas City Power & Light	No	See comments at end of form.
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
City of Tallahassee	No	Please see comment for question 3.
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Exelon Companies	No	Exelon does not agree with the SOE/FR requirements as written but not because of the merging of the R2 and R1 requirements. We believe that there needs to be a streamlined process for entities that are modernizing their system. The SOE and FR portions of this standard are very close to 100% burden to entities that are utilizing modern microprocessor relays connected to GPS clocks for T-lines on their system as a standard. The

Organization	Yes or No	Question 1 Comment
		proposal does not account sufficiently for technical changes that have occurred over the last ten years. The Attachment 1 process is overly burdensome for entities modernizing their systems. An alternative to the attachment 1 process is for an entity to identify that 40% of its BES transmission lines (transformers need not be monitored if lines are monitored) include FR and SER capability. This would be easy to demonstrate as these types of lists are readily available already. Additionally, we believe the reference to BES Elements / Busses needs clarification. We also object to the TO having the responsibility to notify others of their need to comply with a NERC standard, "notify other owners of BES Elements connected to those BES buses".
Response: The standard deals with "what" data is recorded, not "how" it is recorded. Analysis of industry data submitted in response to the June 5, 2013 Request for Data verified that a straight percentage of BES Elements would not be the best way to establish what's needed to have data recorded. Also, please note that Requirement R3 states, "Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each of the BES Elements it owns connected to the BES buses identified in Requirement R1:" As long as the quantities (data) can be determined, the intent of the requirements are met. **The DMSDT does not consider this methodology to be burdensome, and is practical to determine the data that is required. There are BES buses connected to BES Elements owned by different entities. The studies done by the different owners to identify monitored BES buses could yield different results for what needs to be monitored; which necessitates the notification from one Transmission Owner to another.**		
City of Tallahassee	No	see comment for question 3
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Nebraska Public Power District	No	R1 should have some explanation for what the implementation/installation deadlines are for newly identified BES buses as part of the 5 year review. R1

Organization	Yes or No	Question 1 Comment
		states “reevaluate the identified BES buses at least once every five calendar years”, should this read “reevaluate all BES buses at least once every five calendar years”? It seems that new buses may be added and existing buses in the required locations for FR may get dropped down the list and become discretionary. R2 rational states “time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.” Since relays and FR recorders often use separate clocks consider changing “common clock” to “time synchronized clock”. R7 states: “Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5”. Should this read “Each Generator Owner shall have DDR data for each BES Element it owns as notified according to Requirement R5” instead? It seems a bit confusing how to read this requirement. It could be read that the GO “shall have DDR data for each BES Element it owns”. Consider if this requirement can be clarified or restated.

Response: The DMSDT agrees and has revised Requirement R1 to: “1.3 Reevaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.” The Implementation Plan specifies that "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." The intent is to reevaluate all BES buses every five years.

R2: The SDT agrees and has revised the wording in the Rationale Box.

R7: The SDT agrees with you and has revised Requirement R7 to mirror the wording found in Requirement R6:

> **“R7. Each Generator Owner shall have DDR data for each BES Element it owns, for which it received notification as identified in Requirement R5, to determine the following electrical quantities:”**

Organization	Yes or No	Question 1 Comment
PJM Interconnection	No	PJM signed on the SRC's response to this question.
Response: Thank you for the comment. Please see the DMSDT responses to those comments.		
Avista Utilities	No	Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
Response: The bulleted components of Part 5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." The Responsible Entity has the overall view of the BES and is the appropriate entity to determine what data would need to be captured.		
Dominion	Yes	
Northeast Power Coordinating Council	Yes	The term BES bus is not a defined term, it is only described in Step 1 of Attachment 1. Note that NERC's Definition of Bulk Electric System (Phase 2) definition applies to Elements. Requirement R3, sub-Part 3.1 requires to have "Phase-to-neutral voltages for each phase of each specified BES bus". Since BES buses, as described in Attachment 1, may not represent physical buses, this sub-Part is not clear. For example, a breaker-and-a-half design with two physical buses. A Transmission Owner (TO) might not have visibility of the BES classification of Elements it does not own. It is recommended that the TO provide the list of identified BES buses to their PC / RC. The PC/RC will review the received list from the TO, and determine if the list contains BES Elements

Organization	Yes or No	Question 1 Comment
		owned by others, and notify those owners whose BES Elements may require sequence of events recording (SER) and/or fault recording (FR) data. Reference to (undefined) BES buses in Requirement R5 makes this requirement open to interpretations. Sub-Part 5.1.2 requires the inclusion of “Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity”, and its bullets include stability related interfaces or other significant Flowgates, Elements associated with Interconnection Reliability Operating Limits (IROLs), and voltage stability limited transfer paths or load serving areas. The different Parts and sub-Parts of R5 could require a large number of DDRs for TOs which have Flowgates, IROLs, and /or UVLS schemes. The number of required DDRs could become significantly larger than the minimum set of one BES Element plus one additional BES Element for each additional 3,000 MW of load, which could cause excessive burden on some TOs. It is also suggested to eliminate the potential overlap of sub-Parts 5.1.2, 5.1.4, and 5.1.5 by consolidating sub-Parts. Finally, it is recommended that "One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs)" in sub-Part 5.1.4 be replaced with “Any one BES Element critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies” to be consistent with the language in CIP-002-5.1. Sub-Part 5.1.4 requires clarification. The Drafting Team should consider shortening R1 by listing Parts.
Response: Requirement R1 specifies the identification of BES buses. Attachment 1, Step 1 says: "For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing; a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." Under a normal system		

Organization	Yes or No	Question 1 Comment
configuration, the voltages around a station's bus would be the same. Just capturing the data for that "single node" of physical buses is all that is required. The TO only has to know the classification of Elements it owns and ensure that there is data capturing capability for those Elements. The wording of Requirement R5, Part 5.3 was revised to remove BES buses. The bulleted components of sub-Part5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL). The wording of Requirement R5 and its Parts have been revised in response to comments received. Requirement R1 has been revised to break out wording into requirement Parts.		
MRO NERC Standards Review Forum	Yes	
Response:		
Colorado Springs Utilities	Yes	
Response:		
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Response:		
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or

Organization	Yes or No	Question 1 Comment
		more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
SERC Protection and Controls Subcommitee	Yes	
FirstEnergy	Yes	
Duke Energy	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric Power Co	Yes	
Pepco Holdings Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	In general, several requirements stacked into one can lead to missed activities/compliance issues, but we defer judgment on this to the NERC Standards Committee review and standards development guidelines.
Response: Thank you for your comment.		
Luminant Generation Company, LLC	Yes	
ITC	Yes	
Tacoma Power	Yes	Tacoma Power disagrees with the need for this standard. However, assuming that this standard will likely proceed to approval, Tacoma Power takes no exception to merging these requirements.
Response: Thank you for the comment.		
CenterPoint Energy Houston Electric, LLC	Yes	
Entergy Services, Inc.	Yes	
Texas Reliability Entity	Yes	
Oncor Electric Delivery LLC	Yes	Oncor supports combining identification and notification into one requirement as done in the latest draft.
Response: Thank you for your comment.		
Idaho Power Co.	Yes	

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP ("ICLP") agrees that there was no reason to keep two sets of requirements for Transmission Owners, Planning Coordinators, and Reliability Coordinators to identify DME locations, and then notify other equipment owners accordingly. The merger of the two sets of requirements makes sense to us.
Response: Thank you for your comment.		
Northeast Utilities	Yes	
n/a	Yes	
Austin Energy	Yes	City of Austin dba Austin Energy (AE) agrees with the idea of streamlining requirements; however, as noted below in the general comments section (question 3), AE does not agree with this standard as a whole.
Response: Thank you for your comment.		
CPS Energy	Yes	
Puget Sound Energy	Yes	
PNM	Yes	

2. **The DMSDT revised the requirements for dynamic disturbance recording data based on stakeholder comments. Do you agree with the BES Elements requiring dynamic disturbance recording data listed in Requirement R5? If not, please provide technical justification.**

Summary Consideration:

Many stakeholders were unhappy with the bulleted list in Requirement 5.1.2, either with a single bullet or with the list altogether. The standard drafting team revised R5.1.2 and removed the bulleted list of "or" statements, replacing it with "Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL)"

In Requirement R5, the use of "BES buses" was found to be confusing by many stakeholders. The use of this language was simply to provide clarity but, in response to industry's comments, the drafting team revised R5 by removing "BES buses".

Organization	Yes or No	Question 2 Comment
Peak Reliability	No	The reference to the WECC Path Rating Catalog should be removed because the remaining bullet points cover everything in the Path Rating Catalog. The WECC Path Rating Catalog can be changed without going through any Standard development process. Changes to the Path Rating Catalog changes Requirement impact.
Response: The bulleted list of "or" statements has been removed from the standard and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Associated Electric Cooperative, Inc. - JRO00088	No	Note that AECI agrees with the current PRC-002-2 R5.1.2 Bullet#1 wording related to Flowgates, and appreciates this SDT's being thoughtfully responsive to prior comments.FOR: PRC-002-2, R5.1.2, Bullet #5REMOVE: "or relatively low Available Transfer Capability (ATC)"RATIONALE: AECI believes calculated ATC is based upon many complex factors that are somewhat subjective, primarily Market related, and

Organization	Yes or No	Question 2 Comment
		therefore a technically weak indicator for locating where reliability-related DDR equipment should be located.
Response: The bulleted list of "or" statements has been removed from the standard and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
PPL NERC Registered Affiliates	No	We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5.1.2, but not that GOs are the parties that should collect this information. DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data; GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side, so one could apply the same logic as is stated on p.33 of the standard for FR data, "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection." Moreover, as regarding assignment of responsibility for monitoring disturbances, such events are more likely to originate in the transmission system (as was the case for the Northeast blackout of 2003) than in generation plants. The SDT emphasized in its discussion of 6/11/14 with the NAGF Standards Review Team that duplication of equipment is not mandated - a GO can contract with its TO to supply the data if the TO has DME at a plant or is willing to add such equipment. We are concerned that the SDT may not have considered the difficulty in negotiating such agreements for the provision of such data or the transfer of compliance responsibilities. A requirement in the standard that TOs must coordinate with generators to provide the data where they own DME at a generation plant would be preferable if GOs have any responsibility under the standard. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over

Organization	Yes or No	Question 2 Comment
		recordings (GOs) for further analysis. We recommend that the SDT perform a cost-benefit analysis of the two approaches before finalizing this standard.
Response: The Purpose of PRC-002-2 is: "To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." It is important to note that large generating resources are an equal component to the BES and disturbances on the BES as the Transmission system. Tripping of (large) generating Facilities can, and do, pose a risk of underfrequency conditions across an Interconnection. The power grid is a giant, rotating synchronized machine with Transmission lines simply carrying the power generated by power plants. Past experience has shown that using the data from the Transmission grid is insufficient to determine the cause of generator outages. The response of the generating fleet is a strong player in the overall electrical response of the system. As in the 2003 blackout, the 2011 blackout and other blackouts, the sequence of events was able to be recreated using data across the network. Time-synchronized data greatly improved the response and understanding of time aligning the events in the 2011 blackout. However, it is crucial to note that in both cases it is still unclear why the blackout evolved and why generating resources did not respond as expected, or as studied in the power flow and dynamic simulations. For analysis, it is important to understand why the generating plant tripped offline, not when. This information is generally not available because the generating resource owners have insufficient recording capability at the plant to understand how the unit is responding during the transient System conditions. This understanding is required in order for Planners, Event Analysis staff and those responsible for the reliability of the electric grid supposed to create responsive schemes such as Underfrequency Load Shedding Schemes or Remedial Action Schemes to maintain the electrical connectivity of the grid. Generation plays a critical role in the reliability of the electrical grid, and the DMSDT feels that having generator DDR data for large generating resources is a cost effective way to ensure "adequate data to facilitate event analysis of Bulk Electric System (BES) disturbances." **The standard is not concerned with "how" data recording is accomplished, but rather with "what" data is recorded. The standard allows for flexibility without being prescriptive in this respect, allowing the GO to determine the most cost-effective and least duplicative means of recording the data that is necessary for overall reliability and event analysis of the BES. The DMSDT believes that the responsibility for the data lies with the owner of the BES Elements requiring DDR data.**		
SERC Protection and Controls Subcommittee	No	(1) R 5.1.2. Still seems open ended for us. The following bullet points under this requirement give reasons for concern: o Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection o Interfaces between Balancing Authority Areas o Areas of significant congestion,

Organization	Yes or No	Question 2 Comment
		thermal violation history, or relatively low Available Transfer Capability (ATC)DDR are applied for stability reasons, so thermal violations, and low ATC are not valid justification. (2) Depending on how our Planning Coordinator interprets these points, we could still be put upon to install an indeterminately large number of PMUs. This language *is* a step in the right direction from the previous draft of the standard, where "all permanent Flowgates" required DDR equipment, however, our preference would still be to delete R 5.1.2 from the standard. (3) If 5.1.2 is retained, please add a section 5.3 “The number of BES Elements need not exceed one per 1000 MW of its historical peak system Demand.” This provides sufficient coverage in the Responsible Entity’s area and encourages the RE to be ‘responsible’ in applying the 5.1.2 guidelines. (4) Some software vendors do not presently have the full capability as described in Requirement 11 implemented in their equipment or DME application software. This could require change out of the existing equipment. (5) Please clarify the 3rd paragraph of Rationale for R5 by adding ‘only one’ so its consistent with Guidelines and Technical Basis section page 36:’For “major transmission interfaces” with the exception of HVDC, the DDR data is to be captured for only one BES Element, and, is obtainable from one terminal (either end) of an Element.’ Also add: ‘If the BES Element has multiple owners, each TO and / or GO will need to agree which owner will have the DDR data, and the other owners can refer to this agreement as their means of meeting their obligations.’ (6) Please add ‘If the BES Element has multiple owners, each TO (and / or GO, as appropriate)will need to agree which owner will have the DDR data (or equipment, as appropriate), and the other owners can refer to this agreement as their means of meeting their obligations.’ In the rationales for R6, R7, R8, R9, R10, R11, and R12 to be consistent with R5 and cover tie line Elements. Similarly, M6 through M12, add

Organization	Yes or No	Question 2 Comment
		the option that for BES Elements with multiple owners, the TO / GO can provide an agreement stating which owner is responsible for the DDR data. (7) The standard should include direction if agreement between entities cannot be reached i.e. “In cases where agreement between entities cannot be reached, the TO/GO that necessitates DM capability is ultimately responsible for the equipment and any /all requirements.”

Response:

(1, 2) The bulleted list of "or" statements has been removed from the standard and replaced with: “Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).” The concept of “all permanent flowgates” and “major transmission interfaces” was removed from the standard. The more widely used SOL concept replaces these items to capture those major transmission elements.

(2, 3) The Drafting Team understands the concern with overburdening the TOs with DDR data. However, the Drafting Team does not feel that an upper threshold number for DDR coverage be placed; this could lead to insufficient DDR capability applied to the BES particularly in heavily loaded areas where DDR data would be valuable. It is expected and the intent of this standard that the flexibility provided to the Responsibility Entity can be used to utilize existing DDR capability and provide an adequate wide-area view with respect to DDR data.

(4) The draft standard does not dictate that particular DDR equipment have specified software specifications except for the output reporting rate requirement. After consulting with industry subject matter experts, the majority of existing equipment can meet the specifications put forth for data formatting. However, it is also understood that there are software tools available or can be programmed to simply convert one format of data to another format. For example, Phasor Measurement Unit data often reports in C37.118 format, but can be (and often is) converted to COMTRADE format for data sharing purposes. In addition, SER records are being requested in a .csv format to facilitate a more streamlined approach to event analysis from multiple entities, as this is often the biggest bottleneck of the event analysis process. Event records can be easily saved into a .csv format using MS Excel.

(5) The language in the requirements, Rationale Boxes, and Guidance and Technical Basis Section have been revised for consistency.

Organization	Yes or No	Question 2 Comment
(6) It is expected that multi-owner BES Elements will be dealt with in the same manner as any other NERC Standard applicability and the DMSDT does not see the need to try to address the permutations that could possibly arise due to multiple ownership scenarios in this standard. **(7) For multiple ownership, there are already agreements that exist that define who is responsible for what.**		
ISO RTO Council Standards Review Committee	No	Please clarify in R5 whether the first use of the term "BES Elements" is intended to be used here. It appears the intent is that the responsible entities notify all owners of the BES facilities connected to the BES Buses which they have identified. In that case, that term should be "BES Buses" or both BES Elements and BES Buses. We are concerned that the last bullet in Part 5.1.2 may be interpreted to include congestion as it relates to commercial/economic use of transmission interfaces. The term "significant Flowgates" should be limited to only physical/electrical constraints and not congestion that can be mitigated by market mechanisms. Part 5.1.4 needs to clarify whether BES Elements associated with the Interconnected Reliability Operating Limit should include only the monitored element or the contingent element or both. The Rationale for R5 should include the technical reason why the "Responsible Entity" is the applicable entity for identifying buses/elements for DDR events. As stated in the Background Information of the Comment Form, the SDT states the PC or RC has the overall view of the BES for DDR. This explanation should be included in the standard. R5 is also confusing in what is the requirement for BES Element owners which have been identified as needing DDR. We recommend the following changes to ensure the DDRs are applied on the proper BES Elements:" Each Responsible Entity shall (i) identify BES Elements for which dynamic disturbance recording (DDR) data is required, (ii) notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements WILL require DDR data upon

Organization	Yes or No	Question 2 Comment
		request of the Responsible Entity, and (iii) reevaluate the identified buses at least once every five calendar years. ". We are also concerned that this requirement envelopes 3 distinct and mutually exclusive requirements, each of which apply to distinct registered entities and each having different measures. This should be separated into three requirements which will also make the measures for VSL and VRF more applicable. The distinguishing of requirements for clarity in applicability and measurement should be included as an element of the "Quality Review" prior to industry comment posting. R5.1 - The BES Elements that require monitoring shall include the following...R5.2 - The BES Elements that require monitoring in each Responsible Entity's area shall include a minimum of...R5.1.4 requires monitoring BES Elements associated with IROLs. The requirement should only apply to IROLs that are voltage or stability limited: "One or more BES Elements associated with IROLs that are based on voltage or stability performance."

Response:

- **The use of "BES Buses" has been removed from the draft standard; the intent was to provide clarity, but actually resulted in confusion. The intent is that the Responsible Entity will determine BES Elements for which DDR data is required.**
- **Part 5.1.2 has been revised to remove market concerns, as well as to provide clarity: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."**
- **A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires, "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL." The DMSDT has added this to the guidelines for Requirement R5.**

Organization	Yes or No	Question 2 Comment
• **Recommendations regarding the ordering and separation of the body into distinct requirement parts has been incorporated in the draft standard, separating those distinct components into parts of Requirement R5.**		
Seattle City Light	No	As for R1, R5 does not NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify Elements, (2) notify others of Elements, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends revising the first paragraph of R5 to include three subrequirements as follows: R5. Each Responsible Entity shall: R5.1 Identify BES Elements for which dynamic disturbance recording (DDR) data is required R5.2.Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data R5.3 Reevaluate the identified buses at least once every five calendar years. And then renumber the remainder of the requirements to conform: 5.4 The BES Elements shall include the following: 5.4.1 Generating... In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of Elements for which monitoring is required. Seattle suggests that an implementation period be identified for installing DDR capabilities for newly identified Elements similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Response: The SDT has revised R5 based on comments received. **The Implementation Plan addresses data capability for newly-identified buses and BES Elements: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." The Rationale Boxes for Requirements R1 and R5 explain the reevaluation interval – newly-identified BES buses and BES Elements are identified at the five-year reassessment.**		

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	see question 3
Response: Thank you for your comment. Please see responses to Question 3.		
ACES Standards Collaborators	No	We disagree with the identification of BES Elements and the minimum BES Element criteria identified by the SDT. We feel that industry is capable of identifying the number of dynamic disturbance recording devices, "based upon [its] experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We believe this standard should require an entity to generate its own methodology to make these determinations and how often.
Response: Based on the Standard Drafting Team's experience with Disturbance Monitoring and event analysis, along with input from industry subject matter experts (SMEs), the DMSDT believes that the BES Elements outlined in the draft standard are essential for understanding a sequence of dynamic events and recreating those events in simulation to understand what happened and why it happened. The DMSDT believes that capturing these Elements will provide event analysis teams with the necessary measurements to accurately and systematically piece together large disturbances, such as blackouts or Cascading events effectively. Allowing each entity to develop their own methodology could lead to conflicting results.		
Duke Energy	No	(1) Duke Energy cannot envision the reliability benefit of including relatively low ATC as a consideration for the placement of DDR equipment in bullet 5 of R5.1.2. Duke Energy suggests the following revision:"5.1.2 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: o Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or o Transfer Paths in the Western Interconnection Path Rating Catalog, or o Voltage stability limited transfer paths or load serving area, or o Interfaces between Balancing Authority Areas, or o Areas of significant congestion or thermal violation history" If an entity is calculating ATC reliably, there should not be an area of significant congestion or thermal violation history due to the inherent

Organization	Yes or No	Question 2 Comment
		margins (TRM, CBM, etc.) that are built into the ATC calculation. In addition, the ATC consideration is redundant to the previous items in the same bullet.
Response: The Standard Drafting Team has revised Requirement R5 Part 5.1.2 to remove all commercial aspects from the requirement. Requirement 5 Part 5.1.2 now reads, "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Bonneville Power Administration	No	BPA feels checks and balances need to be included to ensure Responsible Entities get concurrence from affected TOs/GOs that dynamic disturbance recording (DDR) data is needed at a given location. Additionally, an IROL is defined as in the Long-Term Planning Horizon, not in the operating horizon. BPA also believes R 5.1.5 needs clarification regarding the criteria for "major voltage sensitive area," - which is related to UVLS (for example, as represented by a metro area of 10 million people / 3000 MW). Otherwise, an isolated radial issue that doesn't impact the Interconnection may be erroneously specified.
Response: The Responsible Entity (RC or PC) assumes the responsibility for selecting BES Elements for DDR coverage because they have the best wide area view of the BES. It is expected that the RC or PC will work with the TOs/GOs to determine the most cost-effective and useful locations for DDR monitoring through the criteria put forth in this standard. The Standard Drafting Team does not feel that an upper threshold number of DDR be placed; this could lead to insufficient DDR applied to the BES, particularly in areas where DDR data would be valuable. It is expected and the intent of this standard that the flexibility provided to the Responsibility Entity can be used to leverage existing DDR equipment currently in operation and provide an adequate wide area view with respect to DDR data. **Regardless of the time horizon, if IROLs are exceeded then there is "… increased risk of voltage instability, Cascading Outages or uncontrolled separation that adversely impacts the interconnection." For this reason, the Standard Drafting Team feels that IROLs should be monitored for Disturbance Monitoring and event analysis purposes. Furthermore, in a NERC reference document (*Supporting Reference for Identification of Interconnection Reliability Operating Limits*), it states: "IROLs are monitored by the Reliability Authority. The [RA] may delegate this task to system operators working for entities performing the [TOP] function, but**		

Organization	Yes or No	Question 2 Comment
it is the [RA] that is held accountable for ensuring that IROLs aren't exceeded." This describes IROLs being monitored in Real-time to ensure they are not violated, just like System Operating Limits. **"Major voltage sensitive area," for the purpose of this standard, is meant to capture areas with in-service UVLS programs to avoid any ambiguity for what is "major voltage sensitive area." The rationale box has been updated to provide further clarification; the requirement has been modified to provide that clarification. However, the DMSDT avoided using ambiguous load density and/or power quantity thresholds. An "isolated radial issue that doesn't impact the interconnection" likely does not require a BES UVLS program to ensure voltage stability.**		
Ameren	No	(1) In addition to our comments we adopt the SERC PCS comments, and include them by reference. (2) As we have stated in our previous comments, we have installed over 30 PMUs on our system over the last 3 years in conjunction with our Planning Coordinator. This required significant effort and resources to perform this installation work. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. We respectfully disagree with the drafting team's brief justification in the Rationale for R5. We still believe the resultant number of PMUs which might be needed under the new standard would be burdensome to most entities. (3) Our software vendor has made known to us that they do not presently have the full capability as described in Requirement 11 implemented in our data concentrator software.
Response: **1. Refer to the Standard Drafting Team's response to the SERC Protection and Controls Subcommittee.** **2. After extensive outreach to industry, NERC Staff and subject matter experts in event analysis, the consensus is, and is opinion of the Standard Drafting Team, that there is insufficient wide area coverage of key Elements on the BES to facilitate accurate, effective and efficient analysis of cascading events or large disturbances. Examples of these types of events or other unexpected contingencies prove that DDR data can provide additional information otherwise currently unavailable to aid in understanding not**		

Organization	Yes or No	Question 2 Comment
only what happened, but why it happened; therein improving the reliability of the electric power grid. Per Requirement R5, your PC will be the Responsible Entity that will determine the DDR requirements. **3. It is important to note that the specifications outlined in Requirement R11 are not required of the vendors of the equipment used to capture the data. There are many offline tools currently in existence for purchase or developed by utility personnel for converting data into formats required for reporting. For example, data can be extracted from DDRs in their standard format such as C37.118 for synchrophasors, and then converted to COMTRADE format for reporting for the purposes of this standard.**		
Independent Electricity System Operator	No	(a) R5 is unclear as it mixes BES Buses with BES Elements. If the responsible entity (a PC or an RC) is to identify BES Elements for which dynamic disturbance recording (DDR) data is required, then it needs to notify ALL such Elements' owners, and there is no need to mention "of BES Elements connected to those BES buses". However, if the requirement is intended to ask the responsible entity to identify BES buses for which dynamic disturbance recording (DDR) data is required, then it needs to notify the owners of the BES buses AND the owners of the BES Elements connected to these BES buses. We suggest the SDT to review the intent of the requirement, and revise it to clearly convey the requirements on what is it the responsible entity needs to identify, and to whom it needs to notify. (b) Part 5.1.2: The term "significant Flowgates" is subject to interpretation since it is not clear what "significant" really means. We suggest the SDT to clarify this term or provide more specificity. (c) Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element or both. This needs to be clarified. (d) Part 5.2: This part requires adding one BES Element for each additional 3,000 MW of an entity's historical peak system Demand, but the word "its" is unclear whether it means the responsible entity (in this case the PC or RC) or the BA. We suggest to reword it to clearly convey that it is the responsible entity's area historical peak system Demand. Note that additional clarity may be needed if the "its" refers to a PC or RC area since within a PC or RC area, there may be multiple BAs and TOPs within

Organization	Yes or No	Question 2 Comment
		which their system peak demand could occur at different times. Thus, Part 5.2 needs to clearly convey whether it is the total non-simultaneous peak demands of all BAs within an area, or it is the one-of highest demand of the entire area

Response:

(a) Requirement R5 has been revised to clarify this issue by removing BES buses.

(b) Requirement R5 Part 5.1.2 has been revised to remove all reference to commercial issues, and now reads: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."

(c) A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple-monitored Element(s) and contingent Element(s). The standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

(d) The ambiguous use of "its" has been removed and replaced with the explicit "Responsible Entity." In addition, the use of "simultaneous" peak system demand has been added to clarify that physical, actual coincident peak is to be used. Further information has been provided in the Rationale and Guidelines sections to help provide clarification and direction for applying this requirement's parts.

Organization	Yes or No	Question 2 Comment
City Utilities of Springfield, MO	No	The R5 language is confusing to me. It appears the Responsible Entity is charged with identifying Elements (not buses), but then the requirement language shifts to notifying owners of Elements connected to "those BES buses" and later reevaluating "identified buses". How are the buses "identified"? Is this an oversight based on the changes made to the earlier version of the Standard? Please clarify.

Response: Requirement R5 has been revised to clarify this issue. The intent is that the Responsible Entity will identify BES Elements for which DDR data is required. They will then notify the owner(s) of those particular Elements that DDR data is required as per this standard. The use of "BES buses" was to simply provide clarify but industry has commented that this is confusing and has thus been removed.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	While AEP has no disagreement with the Elements as specified in R5.1, the standard lacks clarity in what flexibility if any, the Responsible Entity has in selecting them. For example, the text "may require DDR data" implies some flexibility in that regard, and such flexibility should be made more explicit within the standard. It would be more clear if the minimums provided in 5.2 were provided *before* the Elements specified in 5.1 (essentially a swap of 5.1 and 5.2).
Response: The phrase "… may require DDR data" has been revised to "… require DDR data when requested." The intent is that the standard mandates that data be furnished when requested. But how that data is collected is up to the entity required to provide that data. The standard does provide a specific set of BES Elements for which DDR data is required and selected by the Responsible Entity. For example, "major voltage sensitive areas" and "One or more BES Elements" allows for flexibility in the selection of DDR data appropriate for regional variances and different topologies. In addition, the Elements requiring DDR data need not be directly measured and can be determined or calculated assuming this derivation is accurate and time synchronized. The issue of inclusion of Elements for Requirement 5 Part 5.1 and Requirement R5 Part 5.2 has been outlined in the Rationale section of the updated draft standard.		
Seminole Electric Cooperative, Inc.	No	See comments under Question 3
Response: Thank you. Refer to the response to Question 3.		
City of Tallahassee	No	see response for question 3
Response: Thank you. Refer to the response to Question 3.		
Kansas City Power & Light	No	See comments at end of form.
Response: Thank you. Refer to the response to Question 3.		

Organization	Yes or No	Question 2 Comment
City of Tallahassee	No	Please see comment for question 3.
Response: Thank you. Refer to the response to Question 3.		
Dynegy	No	The DDR requirements for GOs are more prescriptive than other regional Criteria or Regional Standards (i.e. NPCC). Recommend the 500 MVA limit be increased.
Response: The Standard Drafting Team used the NERC GADS database to perform a more extensive analysis of generating resource sizes to better understand the coverage requirements relative to the size thresholds to ensure a cost-effective means of capturing large generating resources without overburdening the entire generation fleet across the NERC footprint. This led the DMSDT to selecting the 500 MVA threshold, which the DMSDT feels is justified and representative of a good balance between reliability and cost-effectiveness. DDR data is critical to event analysis for understanding why generating resources do or do not respond as expected. This data provides useful information as to “why” not “when” the unit responds and/or trips based on the electrical characteristics it sees at its terminals. Recording, capturing, simulating and ultimately understanding these responses improves reliability of the BES and overall electric grid.		
Tacoma Power	No	It is unclear what requirements for DDR data changed. The redlined version has only superficial changes to Parts 5.1 and 5.2. Tacoma Power has some concern about the fourth bullet under Part 5.1.2: “Interfaces between Balancing Authority Areas.” While this is only one guideline that the Responsible Entity should (not must) consider, it could potentially place disproportionate burden on entities with a relatively small Balancing Authority Area.
Response: Requirement 5 Part 5.1.2 has been revised for clarity to: “Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL). “		
Entergy Services, Inc.	No	We agree with the revised DDR location criteria reducing the number of monitored BES Elements and appreciate the DMSDT efforts to address that issue. However we are still concerned about the potential for an unnecessarily excessive number of required DDR locations with regard to Flowgate applications. We believe the proposed minimum criterion of “One additional BES Element for each additional

Organization	Yes or No	Question 2 Comment
		3,000 MW of its historical peak system Demand." does specify a reasonable lower threshold which provides adequate wide area coverage and also believe there should be a similarly defined upper threshold on the number of DDR Flowgate (or DDR total) locations required. Suggest DDR Flowgate location criteria be revised to specify no more than twice the adequate minimum number of locations as follows: "Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection (prioritized by the Responsible Entity with area coverage considerations and with a total of no more than one BES Element per 1,500 MW of its historical peak system Demand),"
Response: The Standard Drafting Team has spent much time regarding the selection of DDR, while both specifying specific Elements and allowing for some flexibility. The Standard Drafting Team feels the draft requirement put forth finds a good balance regarding the selected Elements. An upper limit could hinder the capture of additional data in areas that would otherwise enhance and facilitate data analysis. The DMSDT has revised Requirement R5 Part 5.2 and added clarifications to the Rationale/Guidelines to indicate that Requirement 5 Part 5.2 sets a minimum set of BES Elements, while the BES Elements identified in Requirement R5 Part 5.1 are included in the minimum set by Requirement 5 Part 5.2.		
City of Tallahassee	No	see comment for question 3
Response: Thank you. Refer to the response to Question 3.		
Nebraska Public Power District	No	For R5 if the Responsible Entity is slow in notifying owners where DDR data is required does this force the owners to meet the same implementation deadlines or can they extend the deadlines by the same amount of time the RE was late in getting a notification out to the owners? I bring this up because the BES owners will not have any control over the RE schedules but could be subject to shorter implementation deadlines. In addition, since there is some open ended latitude in the ability of the Responsible Entity to identify locations for DDR it is possible that large number of locations could be identified to install DDR in some areas. If this were to occur would there be a possibility for the BES owners to request additional implementation time

Organization	Yes or No	Question 2 Comment
		to become compliant? Consider if some clarification could be added. One option might be to have criteria in 5.1.2 less open ended without any latitude.
Response: As per the Implementation Plan, the clock starts for implementation on the Effective Date of the standard. Any issues with meeting implementation deadlines would have to be vetted through compliance. The DMSDT had previously revised the Implementation Plan to accommodate outage schedules and implementation of all requirements. Requirement R5 Part 5.1.2 has been revised to eliminate any ambiguity, and now reads: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." This revision eliminates the latitude for the Responsible Entity to identify an abnormally large number of locations for DDR data.		
Oncor Electric Delivery LLC	No	Oncor recommends an audit curtailment be added to the DDR requirement similar to what is used in Attachment 1 for the FR's and SER's.
Response: The DMSDT is not aware of any audit curtailments in Attachment 1.		
Ingleside Cogeneration LP	No	ICLP holds to its position that the 1500 MW criteria established in CIP Version 5 for Medium-Impact generation plants is also appropriate for the placement of Dynamic Disturbance Recorders. In our view, the survey that was performed by NERC when the cyber asset bright-line criteria was developed resulted in a reasonable balance between cost and reliability benefit. There has been no corresponding justification provided under Project 2007-11 that would indicate that the 1000 MW threshold is more appropriate.
Response: As stated in the Guidelines and Technical Basis section of the Standard, here is the technical justification: Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those		

Organization	Yes or No	Question 2 Comment
thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet: • The number of individual generating units in total included in the spreadsheet. • The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP. • The total number of units within selected size boundaries. • The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds. • The information in the spreadsheet does not provide information by which the plant location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility. From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA." The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. The incremental impact to the number of units requiring monitoring is expected to be relatively low.		
Northeast Utilities	No	
n/a	No	1. R5 is unclear as to whether the responsible entity needs to identify BES buses or BES Elements on which dynamic disturbance recording data would be required.

Organization	Yes or No	Question 2 Comment
		2. Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element, or both. 3. The standard should not specify a number of BES elements (minimum or otherwise) for which DDR data is required. The number of Elements must be determined as those necessary to capture the necessary data to permit the complete study of key events in the BES and should not be pre-determined in the standard.
Response: Requirement R5 has been revised to clarify this issue. The intent is that the Responsible Entity will identify BES Elements for which DDR data is required. They will then notify the owner(s) of those particular Elements that DDR data is required as per this standard. The use of "BES buses" was to simply provide clarify but industry has commented that this is confusing and has thus been removed. **A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.** **The minimum criteria is meant to ensure a wide area coverage of DDR data across all Responsible Entities; it is expected that this minimum criteria will be met with the BES Elements defined in Requirement R5 Part R5.1, which are defined because they are critical for wide area Disturbance Monitoring and event analysis.**		
PJM Interconnection	No	PJM signed onto the SRC's response to this question.
Response: Thank you for the comment. Please see responses to those comments.		
Austin Energy	No	City of Austin dba Austin Energy (AE), as noted below in the general comments section, does not agree with this standard as a whole. However, AE would like to point out a few clean-up items to Requirement R5. (1) R5 includes the phrase "notify

Organization	Yes or No	Question 2 Comment
		other owners of BES Elements connected to those BES buses". "[T]hose BES buses" implies reference back to BES buses cited previously in the requirement, but they do not exist. R5 requires the Responsible Entity to identify BES Elements not BES buses. The simple fix is to strike "connected to those BES buses." (2) AE believes R5 Part 5.2.2 would read better if the SDT changed the phrase "for each additional 3,000 MW" to "for every 3,000 MW." Otherwise, the Responsible Entity is left asking "in addition to what?"
Response: Thank you for the comment. Requirement R5 and its rationale box have been extensively revised, including Requirement R5 Part R5.2.2. We have removed references to BES buses and Requirement R5 Part R5.2.2 has been revised to "per 3,000 MW."		
CPS Energy	No	Main issue is that "Areas of significant congestion, thermal violation history, or relatively low ATC" is very vague.
Response: The bulleted components of Requirement R5 Part R5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Avista Utilities	No	Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
Response: The bulleted components of Requirement R5 Part R5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	There should be consistency between Parts 5.1.2, 5.1.4, and 5.1.5. The Drafting Team in 5.1.2 and 5.1.5 require DDR on ANY ONE BES Element but in 5.1.4 it uses "One or more BES Elements...". Reading the DT response to the last comment round it seems the intent was to be consistent for these three items; only one BES is required to be monitored. If true then standardize on ANY ONE BES element. Refer to the comments in Question 1.
Response: Thank you for the comment. These requirement parts are worded, by necessity, slightly different due to the criticality of an IROL.		
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SPP Standards Review Group	Yes	We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability.
Response: A statement in the Rationale for Functional Entities was included to provide further clarification, as requested. Thank you for your comment.		
Arizona Public Service Company	Yes	
FirstEnergy	Yes	
DTE Electric	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric Power Co	Yes	
Pepco Holdings Inc.	Yes	
Xcel Energy	Yes	We still believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Response: The responsibilities of functional entities vary by Interconnection; and, therefore, the Responsible Entity is used to capture those variances. Referring to the NERC Reliability Functional Model, this type of analysis fits the PC better than the RC since it does not deal with ahead-of-time or Real-time functions. However, in certain areas/Interconnections, the RC is better suited to perform this analysis either through subcommittees, collaborations or internal staff.		

Organization	Yes or No	Question 2 Comment
Luminant Generation Company, LLC	Yes	
ITC	Yes	
CenterPoint Energy Houston Electric, LLC	Yes	
Exelon Companies	Yes	No Commnet
Texas Reliability Entity	Yes	We agree with the concept of the requirement, however, we suggest moving the methodology for selecting DDR locations described in 5.1 and 5.2 to an attachment and not include it within the text of the requirement itself (similar to the SER/FR bus selection methodology in Attachment 1 for R1).
Response: Attachment 1 is a multi-step mathematical methodology that needs to be separate from the body of the standard. Requirement 5 Parts R5.1 and R5.2 are written specifications that should remain in the body of the requirement to conform with the conventions of NERC Reliability Standards development.		
Idaho Power Co.	Yes	
Puget Sound Energy	Yes	
PNM	Yes	

3. If you have any other comments that you haven't already mentioned above, please provide them here

Summary Consideration:

A number of stakeholders voiced their concerns for more precise wording of the Step 7 in Attachment 1 which stated "If the list has 11 or fewer BES buses: FR and SER data is required at the BES *buses* with the highest maximum available calculated three phase short circuit MVA." The ambiguity arose out of the term "buses" because it could be read as requiring FR and SER data from more than one bus. Thus, Step 7 is now revised to read "If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES *bus* with the highest maximum available calculated three phase short circuit MVA."

Several stakeholders also commented that Requirement R11 had no substantial impact on improving the reliability of the system. The DMSDT notes that the Requirement R11 ensures data availability from the data sources, timely retrievability of the data and common format so that the data can be read and used in the expeditious and effective analysis of events. Requirement R11 provides a reliability impact by integrating all of the previous requirements in the standard with respect to data reporting facilitate event analysis. The first two Parts of Requirement R11 specify how long an entity has to provide requested data (Part 11.1) and also limits how long data must be retained by the TO or GO (Part 11.2). Parts 11.3-11.5 ensure the uniformity and consistency of the data that is reported.

One technical change many stakeholders proposed was to revise Requirement R10 to relate to time synchronization of the device clock rather than data. The Requirement's original language called for time synchronization of SER data within +/- 2 milliseconds. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data. The drafting team revised Requirement R10 accordingly.

Organization	Question 3 Comment
CenterPoint Energy Houston Electric, LLC	1) Regarding R2, CenterPoint Energy believes that breaker open/close operations obtained from the EMS system time-stamped based on RTU scan is adequate SER data for the initial stages of event analysis before detailed disturbance data is obtained from the FR and DDR data that is ultimately required for the actual event analysis. Therefore, CNP recommends removing SER data from R10. 2) Requirement R3 states "...shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES Buses identified in Requirement R1:". CenterPoint Energy believes this language causes confusion with regard to "determining" phase-to-neutral voltages for each phase of each specified BES Bus as required by Part 3.1. The BES Bus voltage can be "determined" by measuring/recording each phase-to-neutral voltage of each line, or by measuring/recording each phase-to-neutral voltage of a smaller subset of lines connected to a BES Bus. The Guidelines and Technical Basis Section describe measuring voltages of "each" line. For entities that are using dedicated fault recording devices, channel capacity can be an issue. In some installations, voltages from 2 or more lines, i.e. a subset of the total number of lines connected to the BES Bus, can be recorded to provide adequate phase-to-neutral voltage FR data for system disturbances obviating the need to record each phase of each line at the recorder. CNP recommends that the DMSDT reconcile the Guidelines and Technical Basis Section language with the Part 3.1 language such that BES Bus voltages can be "determined" by measuring a number of line voltages based on engineering judgment.

Response:

1. SER is included in Requirement R10 to ensure accuracy to facilitate event reconstruction and analysis. The requirement has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following specifications: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

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10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC. 2. The wording of the Guidelines for Requirement R3 was revised to: "Voltages are recorded or accurately determined at applicable BES buses."	
Nebraska Pubilic Power District	It appears, for example, GSU 13.8kV generator buses that exceed the 1500MVA fault current level should be in the bus fault list for FR evaluation. If this is correct they are often ungrounded systems. Can the FR voltages and currents be monitored on the high side of GSU or a tie transformer with a BES tertiary reactor? It seems unclear what currents would be required to monitor as there would not be any ground current at these types of locations/buses if the ungrounded low side must be monitored. R3 and R4 don't specifically mention GSU transformers, GSU low side buses or BES tertiary buses which tend to be ungrounded systems. Can the drafting team clarify that for tertiary or GSUs where the generator bus (for example 13.8kV) is identified in the list of fault buses that it would be acceptable to monitor the voltages and currents on the high side of the GSU or tie transformer? If not, clarify that only the three 13.8 line to ground voltages or 13.8kV line to line voltages are required but not the currents or at least not the ground current. Note that the option of line to ground or line to line voltages is suggested above. Some ungrounded buses may not have line to ground voltages. This may be a concern for some utilities. It seems a bit odd the DDR would be allowed to be on the GSU high side yet still require FR data using the generator bus side voltages as the standard appears to read. R7 seems to address the high or low side requirements better for DDR but clarification for what is required for GSU and generator buses for FR would be helpful since they are often ungrounded systems. For R11 it states: "Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to the Reliability Coordinator". Consider clarifying this wording since it appears to require DDR data is required for R1 to be provided to the RC. R10 also appears to have this concern as well. DDR data is not required by R1, but through the use of the word "and" in R10 and R11 it appears that DDR recording may be necessary on these buses. R12: Is the CAP required to be submitted to the RE or is it upon request similar to the records? This requirement seems like it would be difficult to audit since it would be tracking work on a utilities

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	system. I wonder if the RE is prepared to monitor this information. If they do plan to monitor this is there any other process format or forms necessary or is it understood to be an informal case by case transmittal of CAP status?
Response: Requirement R1 and Attachment 1 applies to Transmission Owners and will exclude Generator Owner 13.8kV buses. **Requirement R11 and R10: The drafting team has revised the language to reflect your concern. Both requirements now read "…all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements…"** **The wording in Requirement R12 was revised to clarify that the CAP is to be submitted to the Regional Entity within 90 days and implemented as follows:** **R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** • **Restore the recording capability, or** • **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**	
Luminant Generation Company, LLC	(1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. These items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents as described below. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting.

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	(3) Requirement R11, subsection 11.4 specifically references "IEEE C37.111-2013". Some older DFRs that effectively capture the needed data may not meet this requirement for the 2013 software update. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This specificity is administrative in nature and does not contributed to a results based standard. This version requirement should be revised to allow for any software versions that the entity has access to that supports the recording and report requirements.
Response: **1. Requirement 11 Parts R11.3, R11.4, and R11.5 facilitate event analysis by ensuring the result of consistency in data to be reported.** **2. Regarding Requirement 11 Parts R11.4 and R11.5 are needed to ensure consistency in the data reported, the analysis of the 2003 Northeast Blackout was hampered by the inconsistent data formats presented to the investigators.** **3. Consistency in data format is important for efficient and expeditious event analysis. The standard does not require that the recording of data be done in a particular format. The data needs to be in the specified format and this can be accomplished for older formats using conversion software.**	
ACES Standards Collaborators	(1) We applaud the SDT's decision to remove the standard-only definitions provided in the previous draft revision. We also approve of the SDT's step to reduce the overall number of requirements listed in this standard. (2) However, we disagree with the SDT's claim that this standard addresses the "what" of data collected and not the "how" the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. In its Consideration of Comments posted May 9, 2014, the SDT rebutted our previous submitted comments with references to the 2003 Blackout in the Northeast. However, it was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As

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	stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability, such as cyber security. (3) We continue to have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the Implementation Plan and based on the effective date of the standard. e(4) We disagree with the previous response to our comments from the SDT, as cited in its Consideration of Comments posted May 9, that "to facilitate expeditious and reliable data capture, it is necessary to stipulate the data formats necessary for efficient data analysis". We feel the SDT could incorporate such stipulation in a separate technical specification or even included as reference within the standard. We feel the technical specifications listed in Requirements R8, R9, R10, and R11 would further strengthen this case, and not subject registered entities to possible violations for every part of these requirements. We feel that technology has significantly improved since the 2003 Northeast Blackout, as manufacturers and industry have supported the need to align such devices on a common frame of time and develop related industry standards accordingly. The SDT even supports this later claim by directly referencing these standards in the text of this proposed NERC standard (see Requirement R11.4). (5) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. We previously alerted the SDT to this observation and reference portions of its response, listed in its Consideration of Comments posted May 9, here. We concur with the SDT that "Disturbance Monitoring recording is necessary to ensure the reliability of the BES by providing the data for a post event analysis that can determine if system improvements are necessary to ensure reliability [and] guide real-time operating decisions." However, we disagree that these "supportive

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	requirements are necessary" and feel that the SDT should take some initiative. For reference, we re-list our observations below. (6) We feel Requirement R11 is arbitrary and could be subject to interpretation from auditors due to Paragraph 81 criteria. TOs and GOs could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their RCs, Regional Entities, and NERC. Furthermore, this requirement meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. This requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. We recommend the SDT should remove this requirement in its entirety. It would be more appropriate to include these specifications in a guideline. Furthermore, we feel portions of requirements R1 and R5 are "Periodic Updates" due to the need to reassess each list of affected BES Elements every five calendar years. Likewise, we feel requirements R1, R5, and R11 are "Administrative" due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be "Data Collection" in nature. Requirements R4.1, R4.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R8.1 and R8.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R9.1 and R9.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R10 requires the collection of data according to specifications outlined for time synchronization. Finally, we feel Requirement R12 is "Administrative" and "Documentation" in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (7) Thank you for the opportunity to comment.
Response:	

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1. Thank you for the comment.

2. The intent of Project 2007-11 is to ensure that there is adequate Disturbance Monitoring data available for event analysis. PMUs are considered DDR, but for a more complete analysis SER and FR data is also needed. SER and FR data is also useful to make Real-time operating decisions. DDR is particularly helpful to analyze generator trips. A guideline will not ensure that there is adequate data available for event analysis as guidelines are unenforceable. As a result of the 2011 Southwest Outage settlement, FERC requires additional PMUs to be installed for reliability enhancements.

3. The standard does not address “how” the data is recorded, and the Implementation Plan defines the requirements for recording capability. In the Implementation Plan, there is a statement regarding compliance for a reassessed list: “Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list.” This language is reflected in the revised Requirements R1 and R5.

4. The Standard Drafting Team discussed the importance of stipulating formats with event analysis SMEs, and, because of its importance, it was decided to incorporate those parameters in the standard. If the data specifications are included in a separate guidance document, there would be no requirement for consistent data to be available for analysis.

5. Thank you for the comment.

6. Uniform data formats are essential to expeditious and efficient data analysis. Because of its importance and necessity in the resulting capture of usable data, Requirement R11 will be maintained. Paragraph 81 is intended to provide an initial review of requirements that may not provide reliability benefit, it is not intended as a blanket reason to remove requirements from standards and is not used by auditors. PRC-002-2 is being developed as a result of an industry accepted recommendation from the 2003 Blackout Report:

“Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.”

NERC Planning Standard I.F — Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. 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

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Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability. **Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their wide area Monitoring System (WAMS).** **Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type, and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.** **Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders."** **7. The Drafting Team thanks you for your comments.**	
Texas Reliability Entity	1. R1 VSL - The percentage and time basis language in the first two parts of the VSLs are confusing: it's unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: "The Transmission Owner identified BES buses as directed by Attachment 1 for more than 80% but less than 100% of the BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement 1 but was late 30 calendar days or less for the once every five year requirement." 2. R5 VSL - The percentage and time basis language in the first two parts of the VSLs are confusing: it's unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table:" The Responsible Entity identified the BES Elements as directed by Requirement R5 for more than 80% but less than 100% of the BES Elements included

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	in R5.1. OR The Responsible Entity evaluated the BES Elements as directed by Requirement 5 but was late 30 calendar days or less for the once every five year requirement." 3. For R3.1 - Attachment 1 states that a ring bus or breaker-and-a-half bus are considered as a single bus. Will the SDT please clarify does this mean that in a ring or breaker-and-a-half substation, only one bus needs to monitored for R3.1? 4. For R11 - We suggest moving the language describing specific formatting requirements in R11.3 through R11.5 to the Guidelines and Technical Basis section of the standard as it is administrative in nature and not performance-based. 5. For R12 - Has the SDT discussed having the entity reporting FR/SER/DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements identified per R5? There may be a reliability gap if the Responsible Entity is not notified due to no requirement for the GO or TO to do so. 6. R11 VSL - The Requirements refer to days and the VSL language refers to percentages. We ask the SDT to confirm that the interpretation of R11 VSLs below is correct. If so, we suggest changing the VSL language to the language provided below. If not, please provide the correct interpretation and possibly revised language to help assure there aren't inconsistencies in compliance and enforcement application. Lower VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 9 days but less than 10 days of the requested data. Moderate VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 8 days but less than 9 days of the requested data. High VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 7 days but less than 8 days of the requested data. Severe VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided less than 7 days of the requested data.
Response: 1. The wording of the VSLs for requirement R1 were revised to reflect revisions to the requirements as well as to add clarifications that you requested.	

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2. The wording of the VSLs for requirement R5 were revised to reflect revisions to the requirements as well as to add clarifications that you requested. 3. For monitoring any particular BES Element, you must be able to determine the appropriate voltages per Requirement R3. 4. Requirement R11 Parts R11.3, R11.4, and R11.5 will remain with the standard. They are important to the effective analysis of system disturbances. Requirement R11 Parts R11.3, R11.4, and R11.5 facilitate event analysis by ensuring the result of consistency in data to be reported. 5. The Standard Drafting Team discussed the submission of Corrective Action Plans to the Responsible Entity. It was decided to just have the CAPs go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its area. 6. The time period in Requirement R11 Part R11.2 does not refer to a quantity of data, but to the time period that the required data must be retrievable for. The percentages refer to how much of the sought after data was produced. The wording of the VSLs for Requirement R11 were revised for clarification by removing the reference to Requirement R11 Part R11.2.	
Manitoba Hydro	1. Implementation Plan- The first paragraph simply describes a date that is synonymous with the Effective Date of the Standard. Accordingly, Manitoba Hydro recommends that this paragraph be abbreviated and made consistent with the third paragraph, by stating that:" Entities shall be 100% compliant on the Effective Date." 2. Similarly, the second paragraph under Implementation Plan describes a date that is three months after the Effective Date of the standard. Manitoba Hydro recommends that the wording be revised to state that: "Entities shall be 100% compliant within three months after the Effective Date. 3. R1 requires transmission Owners to notify other owners that certain BES Elements may require SER/ FR data within 90 days, however it does not specify when the 90 day period runs from. This could be interpreted as running from the Effective Date of the standard or from the day that the BES Element is identified(which could be prior to the Effective Date given that entities must be compliant with applying the methodology and identifying BES busses for which data is required as of the Effective date) . Manitoba Hydro therefore recommends that the ninety day period be clarified.

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	4. R5-(i) For the same reasons stated above, Manitoba Hydro recommends that the ninety day period be clarified. (ii) The contents of the notice to other owners (i.e. that certain BES elements "may" require data) conflicts with R7 which "requires" that an owner who has been notified to determine certain electrical quantities. Therefore, Manitoba Hydro recommends that the "may" in R5 be deleted.
Response: **1., 2.--The Effective Date section addresses the standard as a whole. The subsequent paragraphs refer to different requirements.** **3. The Requirement R1 wording says that Transmission Owners will identify the BES buses, and notify other owners within 90 calendar days. The clock starts when the Transmission Owner identifies the BES buses that have BES Elements connected to it that are owned by others.** **4. Refer to the preceding regarding the ninety-day comment. Requirement R5 stipulates that the Responsible Entity determines the BES Elements for data and has been extensively revised. The DMSDT has removed "may" from R5. Requirement R7 is needed to further specify what data is being looked for.**	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	a. Requirement R11, subsections 11.3, 11.4, and 11.5 do NOT have any impact on the reliability of the system. They are, in fact, entirely administrative in nature. The Results Based Standard template does not support including a requirement of these types. Efforts have been made to remove administrative-type requirements from standards. In this case, a simple mistake in formatting or when naming a file would result in non-compliance with the requirements. b. The GO requirement responsibility should be limited to making available signal sources to the adjoining TO's for the specified list of signals of interest at generating stations. In most cases the TO already owns DM equipment while the GO does not. c. We remained concerned about the cost of the needed equipment where it does already exist; but, we thank the SDT for stretching out the implementation plan which will allow the cost to be allocated over a longer period of time.
Response:	

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a. Formatting and naming were specified to ensure uniformity in recorded data submission to facilitate event analysis. **b. The standard is just concerned with "what" data is captured, not "how" the data is captured. If the Transmission Owner owns DM equipment on the high side, then the Generation Owner may coordinate with the Transmission Owner for data applicable under the standard. Ultimately, the GO is responsible for having the data to be able to determine the applicable quantities under this standard as the existence of the generator necessitates the need for the DDR data.** **c. Thank you for the comment.**	
Wisconsin Electric Power Co	o R1: We suggest that the intent should be that the buses selected according to Attachment 1 will only be those that operate at or above 100 kv ? We believe that this should be specified in Attachment 1. o R2: The Measure M2, Part (1), should be changed to "documents describing the device interconnections and configurations which MAY include a single design standard as representative for common installations... ". This will provide greater clarity that a single design standard is sufficient for evidence, but that it is not required. o R2, Measure M2: In addition, as acceptable evidence, the list in M2 should also include "station drawings" as allowed in M10. o R3: The Measure M3, Part (1), should be changed to "documents describing the device specifications and configurations which may include a single design standard as representative for common installations;", similar to the wording in R2. As written, the Measure would require entities to have a "single design standard", which is not part of the standard Requirements. In addition, a new Part (3) should be added to allow "station drawings" as permissible evidence o R3 and R4: The Generator Owner is listed here, but it is not clear what requirements apply to it, if it does not own any equipment listed in 3.1 or 3.2. In light of the SDT's statements about the superiority of dynamic disturbance recording for generators, we strongly urge that the applicability of R3 and R4 for Generator Owners be removed. o R4: The Measure M4, Part (1), should be changed to: "(1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3)"...

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	o R7: "Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5, to determine the following electrical quantities..." This wording is not clear. We suggest using wording, similar to R6, "Each Generator Owner shall have DDR data for each BES Element it owns for which it received notification as identified in Requirement R5, to determine the following electrical quantities..." o R7: In Measure 7, Part (1), we suggest changing to : "(1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations;" This will allow needed flexibility in providing reasonable evidence. o R8: In Measure 8, make the same change as described above in M7. o R9: The Measure 9, Part (1), should be changed to: "(1) documents describing the device specification, configuration, or settings". o R10: The Measure 10, Part (1), should be changed to: "(1) documents describing the device specification, configuration, or settings". o Guidelines and Technical Basis Section , Guideline for Requirement R2, two statements are made that are at least unclear, if not contradictory: "SER data for generator breaker operations provides little useful data of generator loading." "Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus". Please clarify or revise as necessary.
Response: Buses used in Requirement R1 are identified as BES buses, and will have to conform to the definition of BES. The voltage level does not have to be specified in Attachment 1. **The wording of Measure M2 was revised, as requested.** **The wording of Measure M3 was revised, as requested.** **Generator Owner is used in Requirements R3 and R4 because a Generator Owner may own BES Elements connected to the BES buses identified in Requirement R1.** **The wording of Measure M4 was revised, as requested.**	

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The wording of Requirement R7 was revised, as requested. The wording of Measure M7 was revised, as requested. The wording of Measure M8 was revised, as requested. The wording of Measure M9 was revised, as requested. The wording of Measure M10 was revised, as requested. In the Guideline for Requirement R2, SER data for a generator breaker just gives the breaker position, and not the generator's load. For disturbance analysis, it is important to know the position of every breaker connected to identified BES buses.	
Springfield Utility Board	o Requirement 4, specifically 4.1, requires a single record or multiple records that include “a pre-trigger record length of at least 30 cycles for the same trigger point, or at least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.” This 32-total cycle creates a limit on SUB’s ability to store event reports, and we assume is does for many others, as well. Much of the commonly used and standard software, including that used by Springfield Utility Board, utilizes a 30-cycle event report (2 cycles pre-fault and 28 cycles post-trigger. It does not seem unreasonable to change the language from 32 cycles to 30, so that entities will not incur the unnecessary expense of either purchasing new software or developing a work-around with their current software. o The “buses” language in Attachment 1, Step 7 should be clarified. SUB believes it should read “bus” and not “buses”.
Response: The overall record length of 32 cycles is commonly employed in industry, and is not an unreasonable specification. Requirement R4 Part R4.1 allows for multiple records, as noted in the second bullet: “At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.” The wording in Attachment 1, Step 7 was revised, as suggested.	
American Electric Power	AEP believes that the wording of requirement R11.2 clearly conveys the drafting team’s intent that an entity is not required to retain more than 10 days of disturbance monitoring data at any point in time. Unfortunately, this intent is blurred by the Compliance Evidence Retention’s opening

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	paragraph and the statement that "The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12... for three calendar years." The Evidence Retention, as written, could be interpreted as requiring an entity to maintain three or more years' worth of SER, FR and DDR data. The issue is further confused by the proposed PRC-002-2 RSAW in which the Evidence Requested and the Compliance Assessment Approach for R2, R3, R4, R8, R9, R10 and R11 indicate that SER, FR and DDR data is required to demonstrate compliance and imply that an entity is required to keep all SER, FR and DDR data within the audit window. AEP believes that retaining years of disturbance monitoring data is overly burdensome, provides little to no benefit to reliability and is not the intent of the drafting team. The standard should be revised to align the Compliance Evidence Retention with the Requirements and to more clearly convey the 10 day data retention requirement. The Implementation Plan includes the following "Entities shall be 100% compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." We agree with this statement, but believe it would be more appropriate to include it within the Standard itself, rather than only within the Implementation. R1: The SDT should clarify who takes the lead role to notify other owners when there are multiple owners of a bus. Presumably it would be the company identified as the owner in the fault model being used but this should be clarified. Also, notification alone should not be sufficient in identifying monitored buses. There should be agreement from all owners that a bus should be monitored before it is included in the monitored list, unless it is in the top 10% which indicates it *must* be monitored. R2: It is unclear from the wording of R2 whether the TO/GO must monitor all circuit breakers connected to an identified bus or only circuit breakers connected to the identified bus that are associated with a BES Element. For example, would a 138 kV circuit breaker for a radial fed station service transformer be required to be monitored if it is connected to a selected bus? In this case, the station service transformer would not be a BES Element. We do not believe it would be appropriate to require SER or DFR data in this scenario, but the standard does not explicitly prevent such an interpretation. We suggest making it clear that the element is *both* connected directly to

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	the BES buses identified in Requirement R1 *and* associated with the BES Elements at those BES buses identified in Requirement R1. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. R3: The callout for R3 states “The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured”. The allowance for derivable methods is specified only in the callout, and is not explicit within the standard itself. This allowance needs to remain somewhere in the standard. Guideline for Requirement R3: We are confused by the exclusion “For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system.” We do not understand how the generation currents could be calculated from the transmission currents for faults on the interconnection. In addition, is it the drafting team’s intent to exclude most generating units from fault recording? R12: We see no reliability benefit in sending all CAP’s to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. AEP recommends revising the purpose statement to read “To ensure adequate data is available to NERC to facilitate event analysis of major BES disturbances. AEP recommends establishing only 5 requirements. There should be a requirement for each of the main objectives (establish a data set for FR/SER, establish a data set for DDR, provide FR/SER data upon request, provide DDR data upon request), and a single requirement for repair. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element. AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12.

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	AEP recommends modifying R3 so that only 3 of the 4 currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents.

Response: The intent of the retention period is for the entity to retain the data that has been requested for a disturbance only. The DMSDT has revised the Data Retention section to:

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The drafting team has added a reference to the Implementation Plan in Requirements R1 and R5.

Regarding Requirement R1, Transmission Owners have to communicate the ownership of BES elements connected to a BES bus. The Standard Drafting Team discussed having a "lead" Transmission Owner. It was decided that that would lead to unneeded complexities in the requirement. Specifying agreements is outside the scope of this standard.

Regarding Requirement R2, the Rationale Box for R2 explains: "The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus."

Requirement R3 only applies to BES buses or BES Elements. The DMSDT believes that the requirement is clear as written. Also, the requirement was revised to explicitly state the TO/GO "shall have FR data to *determine* the following electrical quantities…" The drafting team revised the rationale to replace "derivable" to "determinable."

For faults on the Interconnection to generating facilities, the FR data from the transmission substation will capture enough data whereby the data for flow down the Interconnection can be calculated using Kirchoff's Law. Generating units are not included in the FR data capture capability.

Requirement R12: The Standard Drafting Team felt that it is important that the Regional Entity be aware of data recording capability that was out of service. The requirement allows 90 calendar days to determine a timeline for repair or replacement and for a CAP to be submitted to the Regional Entity. The requirement was revised to:

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

- **Restore the recording capability, or**
- **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**

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The Purpose reflects the importance of entities having adequate data recording capability to facilitate their own analysis of events, and develop solutions to prevent those events from recurring. It is beneficial for generators to have DDR to analyze why machines tripped or how they behaved during system disturbances. **The Standard Drafting Team combined and edited requirements from the November posting to reflect comments received. The remaining requirements reflect the Standard Drafting Team supporting the Purpose of the standard.** **The Rationale Box for Requirement R3 explains the need for the three phase currents and the residual or neutral current. Note that Requirement R3 reads "...to determine the following electrical quantities..."**	
Northeast Power Coordinating Council	An additional implementation requirement or effective date should be included to address the situation when after the 5 year evaluation an additional element is identified for FR or DDR to afford the TO or GO to budget and install additional equipment. The draft PRC-005-X standard included language to address this in its latest draft. Consider adding to the technical guidelines for R6 more information surrounding the allowance for the use of a common bus voltage measurement where appropriate to monitor multiple BES Elements. Suggest adding to the second paragraph in the guideline for R6: The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require measurement of each BES Element where a common bus measurement is available. Where a common measurement is utilized the Owner must plan the installation such that a bus outage would not result in the DDR data to be compromised. For example,...etc..... Part 11.4 requires the use of C37.111-2013. This could be an issue if an Entity has not upgraded its equipment of firmware. In R8 an exception is allowed for DDR owners with older equipment. A similar tack should be applied here. The Standard should not force replacement. Attachment 1 does not specify how to distribute an odd number for 20% of the BES buses between 10% of the BES buses and additional 10% of the BES buses (both determined in Step 6), e.g. if twenty-one (21) buses in total are required.

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	Requirement R8 should allow legacy equipment to have multiple triggered records which when combined into one time synchronized record make up the required length of three minutes. Requirement R11, Part 11.3 requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. Can the Drafting Team provide a name of DME which gives the data in this format? Requirement R11, Part 11.4 requires FR and DDR data in C37.111 (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE) formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? Requirement R11, Part 11.5 requires data files to be named in conformance with C37.232 IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME) whereas the majority of DME equipment does not save data in this format.
Response: It is stated on Page 4 of the Implementation Plan that: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." **The drafting team added the sentence, "The intent of the Standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available." The DMSDT did not believe that the second sentence is necessary as a lead-in to the example.** **The drafting team agrees that there is inconsistency between requirements for using older equipment and data format. The version of COMTRADE has been revised to 1999 or later.** **Whether an odd or even number of buses should not affect the distribution of buses. The requirement is for a minimum of 20 percent so you need to round up.** **Combining multiple triggered records to one time synchronized record of at least three minutes in length is acceptable.** **The drafting team can provide manufacturer information, but does not believe it is appropriate to provide that in a public record. Feel free to contact a member of the team for this information. The format specified in Requirement 11 Part R11.3 is for**	

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consistency. The standard addresses "what" data is captured, not "how" it is captured. The equipment to capture the data to conform to the standard is readily available. **Regarding Requirement 11 Part R11.4, manually converted records are acceptable, as long as the data is submitted in the specified format.** **Regardless of the file naming convention of your equipment, for consistency, submitted data files are to be named in accordance with Requirement 11 Part R11.5. You may save your files internally using any file naming convention you desire.**	
Peak Reliability	Applicability section: the Responsible Entity in all Interconnections should be the Planning Coordinator or Reliability Coordinator. R5.1.2, bullet 1, the term "significant Flowgates" appears to be undefined. Does it need to be clarified? R8: undervoltage trigger set no lower than 85% of normal operating voltage - what is normal operating voltage? For a 500 kV system, is it 500 kV or is it the average bus voltage for a specified period of time (such as 525kV)?
Response: Applicability: The responsibility of determining these locations fall on the PC, per the Functional Model. In some areas, this responsibility has been assumed by the RC and that is reflected in the applicability for the standard. **Requirement R5 Part R5.1.2 – all flowgate information has been removed. Requirement 5 Part R5.1.2 now reads "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."** **Requirement R8: The normal operating voltage is intended to be what voltage a system would normally be operated based on scheduled voltages.**	
Dominion	As stated in Dominion's previous comments: "PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability

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	Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01).” The standard drafting team (SDT) in response provided:” The DMSDT is aware that the NPCC DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved.” While Dominion appreciates the SDT response, the fact remains that NPCC applicable entities continue to implement the FERC approved NPCC Regional Reliability Standard that could result in over/under installing DM capability when compared to PRC-002-2, once approved. Therefore, Dominion again urges the SDT to include a Variance in PRC-002-2 that excludes entities subject to PRC-002-NPCC-01 from the applicability section of this standard.
Response: The Standard Drafting Team has taken into consideration the approved and in-place NPCC PRC-002-NPCC-01. The Standard Drafting Team is aware that PRC-002-NPCC-01 applies to the BPS as defined in the NPCC A-10 Criteria. While that is not as comprehensive as the new BES and in force BES definition, PRC-002-2 is about "what" data is captured, not "how" the data is captured. It is impossible to make a blanket statement that meeting the requirements of PRC-002-NPCC-01 will meet the requirements of PRC-002-2. The Standard Drafting Team is sure that at the least, meeting PRC-002-NPCC-01 will provide a very good foundation for having the capability to capture the data asked for in PRC-002-2. If "over installing" Disturbance Monitoring capability was done, from an engineering and operations perspective that is only positive. The DMSDT is coordinating with NPCC to retire PRC-002-NPCC-01 upon approval of PRC-002-2.	
American Transmission Company, LLC	ATC asks that the SDT consider the following recommended changes to add clarity to the subrequirements: R5.1.2, bullet 1 - Add “as judged by the Responsible Entities,” to end of statement. R5.1.2, bullet 4 - Add “(not local Balancing Authorities)” after “Balancing Authority.” R5.1.2, bullet 5 - Add “as judged by the Responsible Entities,” to end of statement. R5.2.2 - Add “within the past 10 years” to the end of statement for time clarity.

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Response: Regarding Requirement 5 Part R5.1.2, the bulleted list has been deleted and the language is now "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." It is not necessary to be restrictive on the time frame for the historical peak system Demand in Requirement 5 Part R5.2.2.	
HHWP	Attachment 1, Step 7 states: "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9."It seems that word "buses" in this sentence should be changed to "bus".
Response: "Buses" was changed to bus.	
ISO RTO Council Standards Review Committee	Attachment 2: acceptable states are OPEN or CLOSE but other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also commonly used. The format should allow for regional variations in terminology. Otherwise, it could become time consuming for TOs and GOs to provide the SER data.
Response: The DMSDT agrees and has revised the footnote in Attachment 2 to read: OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.	
Bonneville Power Administration	BPA does not believe the Cost Effective Analysis Process (CEAP) uses an appropriate comparison example, without clarifying between the 2003 Interconnection wide-area, numerous-state blackout and the 2011 local-area, three-state blackout within an Interconnection, as the 2011 event would naturally take less time and data. BPA does agree, however, with the synchrophasor (PMU) data-speed impact.
Response: Thank you for the comment.	
Austin Energy	City of Austin dba Austin Energy (AE) does not agree with this standard as a whole. AE believes it is too prescriptive and unnecessary in the ERCOT region. Regional requirements for ERCOT regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1.

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	(http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring.
Response: Thank you for your comment. The standard drafting team notes that the ERCOT Operating Guide is not a standard and is not enforceable. PRC-002-2 is a proposed mandatory standard and its requirements were directed at "what" data is captured, not "how" it is captured.	
Puget Sound Energy	Could we use one BES location for both DDR equipment and FR/SER equipment?
Response: As long as the standard's requirements are met, one location could be used for SER, FR and DDR capture.	
Entergy Services, Inc.	Entities with a significant number of DDRs and have DDRs which include installations where manual data retrieval is necessary should be allowed more than 30 days to collect, format, assemble and review data for submittal. Add provision for a data request submittal extension such as “R11.1 The recorded data will be provided within 30 calendar days of a request unless an extension is granted by the requesting authority.”
Response: The Standard Drafting Team has added your requested language to Requirement R11 Part R11.1 regarding an extension.	
CPS Energy	First issue is that we find the methodology for determining which BES busses may require SER or FR data to be overly complicated and difficult to follow. If the methodology is going to be this complicated, then perhaps the Planning Coordinator or Reliability Coordinator is best suited to perform this analysis so that Transmission Owners do not fall out of compliance for failing to understand an overly complicated spreadsheet with more than 17 steps to determine which busses require this equipment. The second issue is with the requirement of time synchronizing SER data to within +/- 2 milliseconds. While the intent of the standard appears to be to allow many modern existing relays that sample waveforms at 16 samples/cycle, have SER capabilities, and can synchronize to a GPS clock within less than 1 millisecond, this requirement will actually prohibit many of the relays because of the SER requirement. For example, a widely used SEL-311C relay can have its clocked

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	synced to within 1 microsecond, the SER is only time-stamped once every quarter cycle, which is the processing interval of the processor. This means that the SER can only be accurate to within +/- 5 milliseconds. We think this may not be realized by the drafting team and/or many stakeholders. Additionally, we believe that the +/- 5 millisecond accuracy should be more than accurate enough if only a breaker status is required by SER. Two things to note: 1) the breaker 52a or 52b contact that would be input into the DFR device is a mechanical moving device that in and of itself may not be that accurate in regards to an actual indication as to whether the breaker is open or closed. These contacts can often be adjusted as to when they make and occasionally are even wrong in regards to status. 2) Each breaker requiring SER is in many cases already being monitored for currents that give a change of status as to the breaker being open or closed.
Response: The Transmission Owner is the appropriate entity to perform the analysis for BES buses because the Transmission Owner is more familiar with the intricacies of its system than the Planning Coordinator or Reliability Coordinator. **Requirement R10 has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard.** **"R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following specifications: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** **10.1 Synchronization to Coordinated Universal Time (UTC), with or without a local time offset.** **10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC."** **The Standard Drafting Team acknowledges that the auxiliary switch or other inputs to SER for breaker status are not precise. Current through a breaker may be zero without a breaker opening. Breaker position status data is necessary for disturbance analysis. For multiple feeder tripout disturbances, circuit breaker SER data has been useful in making timely restoration decisions.**	
Associated Electric Cooperative, Inc. - JRO00088	FOR: Appendix #1, Step 6, Paragraph 2REPLACE: "buses with the highest" WITH: "bus with the highest" RATIONALE: Clarity - As this process step seems to yield one identified bus, presumed to

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	fill the void of its successor bullet's 10% minimum count, the use of "required at" in conjunction with "buses" is confusing. FOR: PRC-002-2, R5.2, Guidelines ECI believes the guideline for 5.2 should provide sample calculations for the number of DDRs required: 1) for an entity having 5999 MW Historical Load, and 2)for an entity having 6000 MW Historical load. While we believe the answer for 1) is only 1 DDR, and for 2) 2 DDRs per R5.2, the Webinar presenter mentioned some expectations for Rounding which introduced uncertainty that the above example could address.
Response: The drafting team has revised "buses" to "bus" as requested. **Requirement R5 Part R5.2: Your answers are correct. Part 5.2 has been revised to:** **5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:** **5.2.1 One BES Element** **5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak system Demand.**	
Oncor Electric Delivery LLC	General: It is understood the Rationale Boxes will be retained but relocated to the "Guidelines and Technical Basis Section" of the Standard. If the "Guidelines and Technical Basis Section" cannot be used as compliance validation to auditor(s), it is imperative the requirement language be paired to the alternatives specified in the Rationale language. Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. Incorporating the Rationale/intent language into the Requirement or Measurement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore, Oncor recommends the DMSTD review the Requirement/Measurement language and the corresponding Rationale language to ensure there are no gaps. Specifics are provided below: R2: Legacy FR equipment installed before the Standard effective date may not be capable of embedded SOER. R2 does not afford the same caveat for older equipment where SOER is required that R8 provides for older equipment where DDR is required. Language should be added to R2

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	providing the option to utilize FR digitals to monitor circuit breaker position for required circuit breaker position monitoring.R1 and R5: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists after approval of the standard, but the Requirement language itself does not include post-implementation "5 year re-evaluation" compliance timelines for the required reassessments. "Re-evaluation time frame implementation" language should also be included in the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3 and R6: A Rationale should be added that the required “electrical quantities can be determined (calculated, derived, etc.)” to R3 and R6 as described below: o The R3 Rationale explains the method of deriving electrical quantities. The language of R3.1 does not reflect the intent described in the Rationale. Specifically, whether locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each Phase-to-Neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for “each line or bus.” o The language of R6.3 does not specify the method used to provide “Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.” If a single phase voltage and current are collected for R6, is it acceptable to calculate power flows expressed on a 3 phase basis derived from single phase quantities? Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR.R10: The "Rationale for R10" language, "Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset." Hence, requested records must be supplied in UTC format, but the collected and stored format do not. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.R10: Additionally, the "Rationale for R10" language should provide a caveat to allow for manipulating event records to UTC for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the “or derived” language suggestions to Requirements R3 and R6 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M11 evidence. Similar to

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	the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.R11: (Requirement 11.4) If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR analysis. Relay Synchrophasor data is not compatible with the legacy COMTRADE format.R11: (Requirement 11.5) Additionally, add "Rationale for R11" language, "Collected and stored data does not need to follow the "C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)" file naming format. The data provided pursuant to a data request must be provided in the C37.232 file naming format. Similar to the "R3 and R6" comments above, the Requirement 11.5 and/or M11 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.
Response: The intent of a rationale box is to explain and clarify the intentions of the associated sections of the standard. After approval, the rationale boxes will be moved to the end of the standard, prior to the Guidelines and Technical Basis Section. The requirements of the standard are what will be audited; the rationale boxes are for an entity's or auditor's reference. The Standard Drafting Team reviewed the requirements and their associated rationale boxes to ensure consistency and completeness. **Requirement R2--PRC-002-2 addresses "what" data is recorded, not "how" it is recorded. Because of the significant differences between legacy DDR equipment and modern continuously recording DDR equipment it was necessary to address those differences in the standard.** **Requirements R1 and R5--The Implementation Plan specifies that: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."** **Requirements R3 and R6--The wording in the rationale boxes for Requirements R3 and R6 was revised to clarify the intention of the requirements. Having adequate electrical quantities to calculate or derive other electrical quantities is the intent of these requirements.** **Requirement R10--The wording in the rationale box for Requirement R10 was revised for clarity. Data provided must be in the UTC format. The standard is addressing in what format the data must be provided.** **Requirement R11--Data must be provided in the formats specified to ensure uniformity to aid event analysis.**	
Liberty Electric Power, LLC	Generator owners should not be required to install DME. Generators do not model the BES, have no overall awareness of the state of the BES, and are not monitoring the overall state of the BES.

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	The requirement should be, at most, to provide a signal showing breaker position to the TO. Requirements for GOs to provide equipment are properly the realm of the interconnection agreement, not a NERC standard, and the SDT is intruding on the contractual relationship between REs.
Response: The standard deals with "what" data is captured, not "how" it is captured. It is not intended to require redundant data capture. The goal of the standard is that the data be captured. The SDT disagrees with any statement or implication that GOs should not be responsible for DDR data in PRC-002-2. Whether a GO has need or use for DDR data for its units does not impact the grid's need for it for event analysis – which benefits all users, owners and operators of the BES - after a system event. And it is consistent and logical practice in all NERC standards that owners of BES equipment are responsible to provide data required by that standard, for the BES equipment they own. Consequently GOs are correctly responsible in PRC-002-2 for the DDR data required from their units by the standard, not others such as TOs.	
Ingleside Cogeneration LP	ICLP has been closely following the distribution of the Cost Effectiveness Analysis Process (CEAP) survey and its results. We agree with the general findings that the existing base of Disturbance Recorders are mostly sufficient to meet PRC-002-2's locating and capability requirements - and that the reliability benefit of adding more equipment is minimal. However, it seems to us that NERC's and the Regional Entities' data analysis teams feel that the information provided in the evaluation of recent events is still lacking. This conflicts with the equipment owner's opinions and should be reconciled. Unfortunately, the only justification seems to be that the 2003 investigation recommended the action and FERC directed it be done. This is not a minor point. The benefits of reliability oversight at the national level may be the most difficult to assess, but are the most important. Every dollar spent on compliance needs to be properly allocated, otherwise it will go to less important initiatives. As such, ICLP urges that another CEAP survey be performed - but this time by the ERO community. Any perceived value should be quantifiable, so that it may be compared to the costs we all take on.
Response: Thank you for the comment. The CEAP process was performed and endorsed by the NERC Standards Committee for this standard. It is not meant to be a cost/benefit analysis. It is intended to be a cost-effectiveness analysis to provide stakeholders an	

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opportunity to provide potential costs associated with the standard, as well as potential alternative solutions that would meet the intent of the standard.	
MRO NERC Standards Review Forum	In both R3 and R4 it appears the applicability is for Transmission Owners and Generator Owners but the GO typically does not own a substation bus, transformer with a low-side of >100 kV, or transmission lines (as a registered entity of GO). We believe Generator Owner should be removed from these requirements. In R5 please consider the following modifications:R5.1.2, bullet 1 - Add "as judged by the Responsible Entities" to the end of the bullet.R5.1.2, bullet 5 - Add "as judged by the Responsible Entities" to the end of the bullet. R5.2.2 - Add "within the past 10 years" to the end of the requirement to provide a reasonable and finite time frame. The NSRF interprets R11.2 to say that NERC/Regions will always submit a request for data within 10 days of an event, so it is not necessary for DME's to hold data longer than that timeframe. As this impacts the memory/storage capability of the equipment we would appreciate clarification as to how the 10 days was determined and if the SDT believes the timeframe is long enough.
Response: The DMSDT disagrees with any statement or implication that GOs should not be responsible for DDR data in PRC-002-2. Whether a GO has need or use for DDR data for its units does not impact the grid's need for it for event analysis – which benefits all users owners and operators of the BES - after a system event. And it is consistent and logical practice in all NERC standards that owners of BES equipment are responsible to provide data required by that standard, for the BES equipment they own. Consequently GOs are correctly responsible in PRC-002-2 for the DDR data required from their units by the standard, not others such as TOs. **Regarding Requirement 5 Part R5.1.2, the bullets have been removed and the sub-part revised to: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."** **Requirement R5 Part R5.2.2: It is not necessary to be restrictive on the timeframe for the historical peak system Demand in Requirement R5 Part R5.2.2.**	

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Your interpretation is correct. Data will be requested soon after a major incident. The Drafting also considered available storage capabilities, and it judged 10 calendar days to be an appropriate timeframe.	
ITC	ITC feels that the Requirement 10 specification of + 2 milliseconds of Coordinated Universal Time (UTC) is too restrictive for a number of industry wide installed modern microprocessor based relays. These relays have proven to be reliable from a protection, SER, and FR perspective. Additionally, the present PRC-018 standard indicates that a DME's clock shall be synchronized within 2 ms. ITC agrees the PRC-018 synchronism requirement would be acceptable for SER device clocks but not data. It is recommend that the DMSDT consider changing the tolerance level for breaker status SER to be within 10 milliseconds. This would allow the continued use of these microprocessor based relays. This will be consistent with DMSDT guidance that microprocessor relays are acceptable implementations of SER and FR.
Response: Requirement R10 has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard. **"R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** **10.1 Synchronization to Coordinated Universal Time (UTC), time stamped with or without a local time offset.** **10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC."**	
Lincoln Electric System	Per Attachment 1, Step 1 utilities are instructed to "Determine a complete list of BES buses that it owns." A complete list of BES buses could include tap buses feeding radial load where there would be no BES circuit breakers or relaying and therefore no ability to gather the data pertinent to this standard. The SDT response to LES' previous comments stated that, "If a tapped substation was not modeled in a system study as a bus then it would not be considered a bus." If this is the drafting team's intent, it should be clearly stated in Step 1 that tap buses with no BES breakers or relaying are not to be included. Doing so eliminates any possible confusion associated with

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	whether a bus has been included in a system study. Whereas a Planning study model may not include these buses, a System Protection study model would in consideration that non-BES transformer relaying at the tap has to be coordinated with relaying at adjacent substations. R11.2 specifies "The recorded data will be retrievable for the period of 10 calendar days preceding a request." For clarity, LES suggests restating R11.2 as follows: "The recorded data will be retrievable for the period of 10 calendar days following the date that the data was recorded." Wording it this way ensures that the 10 calendar day timeframe starts on the day that the data was recorded. If left unchanged, the existing statement would tie the 10 day timeframe to the date of the request which makes the timeframe indefinite given the fact that the requesting entity has no time limit on when a request can be made.
Response: The DMSDT has revised the first sentence to: "For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid." **The wording of Requirement R11 Part R11.2 was revised as suggested.**	
PJM Interconnection	PJM urges the drafting team to reconsider including some type of alternative method for determination of the BES buses requiring sequence of events recording and fault recording as stated in the BES detailed methodology included in R1 and detailed in Attachment 1 of the standard. PJM suggested an alternative method that would be less burdensome for entities working on installation of or already have installed modern equipment with FR and SOER capabilities on their circuits. PJM appreciates the drafting team's consideration of our proposed alternative method and understands that it is not included in the draft standard presently posted. PJM feels strongly regarding inclusion of some type of alternative method and therefore will be submitting a negative ballot for the draft standard.
Response: The Standard Drafting Team evaluated methods of determining how to locate SER and FR data recording capability, and decided on Attachment 1 as being the best universally-applicable option. The DMSDT does not believe that the methodology is burdensome. The methodology only asks for BES buses rather than line terminals and only requires at least 20 percent coverage. This reduces the compliance burden for each entity.	

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Exelon Companies	R1: See comments to question 1. R2: It is not necessary to monitor circuit breaker auxiliary contacts to figure out when a circuit breaker opened or closed. Loss of current can be monitored in a fault recorder. This requirement puts a high burden on identifying print #s to show circuit breaker auxiliary contacts are connected to relays with SER capability. This effort is just not necessary based on our experience investigating thousands of operations over the years. The drafting team should eliminate this requirement or modify it to clearly state that cessation of current can be used to determine when circuit breakers open. R3: T-lines are exposed to a much higher number of faults/operations than T-transformers. Thus, modernization of T-line protection provides the greatest increase to reliability by a large margin. Having modern relays on T-lines allows for deducing current in transformers if necessary. The drafting team should concentrate on lines rather than transformers as the industry is doing. The drafting team should remove transformers from R3 since this information can be deduced from line monitoring or change R3.2.1 to state Transformers… "only when sufficient line monitoring is not present to derive transformer quantities". R4: No comment, previous changes made by the drafting team addressed our concerns. R5: No comment, previous changes made by the drafting team addressed our concerns. R6, R7, R8: No comment. R9: The drafting team should eliminate requirement 9.1 unless they are aware of a significant portion of the industry installing equipment that doesn't meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R10: The drafting team should eliminate the requirement of within +/- 2 msec of UTC unless they are aware of a significant portion of the industry installing equipment that doesn't meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R11: No comment.

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	R12: We're using microprocessor relays for FR and SOE capability. They are tested under PRC-005 and alarmed upon failure. We should not have to keep track of every relay that fails on the system that we fix or replace for this standard. We have plenty of incentive to keep our relays working already and we don't run with failed relays for 90 days. Hence, there is no need for R12 and it should be eliminated. It is 100% burden, a complete waste of engineering resources, and hence a detriment to overall reliability. If the drafting team will not eliminate this requirement, it should be re-worded such that it is very clear that we do not need to keep track of failures that are rectified within 90 days. We should not have a compliance burden to prove that we fixed something in 2 days. An overall comment is that we believe this standard is not required for FR and SOE. These functions are built in to modern relays being adopted industry-wide already. All the requirements related to FR and SOE should be eliminated and the standard written to address DDR only. It is even arguable that this standard is required to promote DDR capability as the widespread use of synchrophasors including their storage has greatly expanded since 2003.

Response: R1: Please see responses to Question 1.

Requirement R2: Current through a breaker may be zero without a breaker opening. Breaker position status data is necessary for disturbance analysis. For multiple feeder tripout disturbances, circuit breaker SER data has been useful in making timely restoration decisions.

Requirement R3: Requirement R3 states "...to determine..." As you intimate, an entity just has to be able to determine the quantities in the requirement.

Requirement R9 Part R9.1: Even though 960 samples per second is common in industry, Requirement R9 Part R9.1 was included to ensure adequate accuracy for calculations.

Requirement R10: Even though +/- 2 miliseconds is common in industry, Requirement R10 was included to ensure adequate accuracy for calculations. R10 was also revised to provide clarity:

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"R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **10.1 Synchronization to Coordinated Universal Time (UTC), time stamped with or without a local time offset.** **10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC."** **R12: If you have compliance data for PRC-005 that meets the requirements in Requirement R12, then you can use the same data for compliance with PRC-002, Requirement R12. Requirement R12 stipulates that for a failure of recording capability an entity has ninety 90 calendar days to get it restored, or file a Corrective Action Plan. SCADA logs could also be used as evidence and this has been added to the measure.** **PRC-002-2 ensures that there will be "...adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." This includes FR and SER data as they are critical items that assist in determining what happened during a disturbance.**	
ReliabilityFirst	ReliabilityFirst has the following comments for consideration: 1. Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 if plant that has six 200 MVA units, does this plant require any DDRs? As currently written, ReliabilityFirst believes no DDRs are required at this facility. From a monitoring perspective, ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR. 2. Requirement R12, Part 6.1.3.2 - ReliabilityFirst does not understand the reasoning behind requiring the submission of the timeline for restoration and a Corrective Action Plan (CAP) to the Regional Entity. Without a requirement for the applicable entity to "implement" the CAP, the Regional Entities will have little recourse and there is little value in having the CAP if there is no requirement to complete it. Theoretically, the CAP could go on in perpetuity without completion and the entity would still be compliant, but the problem would remain unresolved. Furthermore, if the requirement requiring the applicable entity to "implement" the CAP, the Regional Entities can monitor implementation through a Regional Entity monitoring method. ReliabilityFirst recommends removing the "for submission to the Regional Entity" language and include

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	implementation language as follows:i. "...restore the recording capability or develop a timeline with milestones for completion for restoration and implement a Corrective Action Plan (CAP)." 3. VSL for Requirement R2 - ReliabilityFirst believes the gradation of VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). As written, if an entity only had 51% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers they would only fall under the moderate VSL. ReliabilityFirst believes missing close to half of the total SER data is completely missing the intent of the requirement and should be designated as a "Severe" VSL. ReliabilityFirst has a similar comment for the VSLs associated with requirements R3, R4, R6, R7, R8 and R9.

Response:

1. The reference is to Requirement R5 Part R5.1.1. A plant with six 200MVA machines would not be required to have DDR. The Standard Drafting Team intended to establish generating resource monitoring requirements to develop a foundation for which data is required to be captured.

2. Referring to Requirement R12, the Standard Drafting Team decided to have the CAP submitted to the Regional Entity because of its overview of the system. Corrective Action Plan is defined in the NERC Glossary of Terms as:

A list of actions and an associated timetable for implementation to remedy a specific problem.

The CAP therefore, would include a timeline for restoration. The Drafting Team did not want to get more specific on milestones for restoration of the capability because from experience it is unrealistic to place milestones on returning the capability to service because of uncertainties in supply and delivery of what is needed to make restoration. The Drafting Team revised the wording in the requirement and Rationale Box. The Regional Entity would determine if the timetable was acceptable.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

- **Restore the recording capability, or**
- **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**

3. The DMSDT concurs and has made the revisions as suggested.

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Seattle City Light	Seattle appreciates the efforts of the Drafting Team to respond to comments received following the initial posting of this draft Standard. However, Seattle fundamentally disagrees with the approach proposed by draft PRC-002 for several reasons. 1. First, the proposed Standard requires an entity to establish at least 43 new controls to meet the compliance assessment approaches identified in the draft RSAW, and this figure does not consider the dozen or additional controls required to ensure all Attachment 1 steps are met. For context, consider that approximately 4-5000 controls are required to meet the entire body of NERC Standards. As such proposed PRC-002 represents a 1% increase in the overall compliance burden on the electricity enterprise. Entities will be required to monitor performance of minor activities, and auditors likewise will be required to examine performance. Seattle does not believe the reliability benefit offered by this Standard warrants this new compliance burden. Indeed each requirement of PRC-002 is identified as “Lower” for violation risk factor (the lowest rating possible), indicating that the drafting team does not consider any requirement of the Standard to have a critical impact on BES reliability. Rather this Standard supports long-term operational improvements in the BES. Seattle believes such improvements are important and supports a reasonable approach to disturbance monitoring, but does not support the complex, over-engineered Standard. 2. The bus screening process is an example of a process that needs to be simplified. The rational does not seem to be well thought out and is certainly not easy to explain and implement (worse than the FERC Order 754 exercise that industry recently participated in). The attached Excel spreadsheet and the directions for completing it are very cumbersome and inefficient--a lot like trying to fill-out a Federal Tax form. Instead of giving an entity the metrics to be achieved, this approach attempts to create a cookbook format where data needs to be entered in one part of the spreadsheet, and then subtracted out in another part of the spreadsheet. 3. Seattle believe appropriate and reasonable a general requirement to have disturbance monitoring, but believes the technical requirements for data type, frequency of sampling, and so forth would be better handled in a criteria or guideline document. Once such requirements are codified as federal law it is cumbersome and lengthy process to change them, yet all are aware how fast technical change has occurred in the area of disturbance monitoring. Moving

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	the technical requirements from the Standard to a guidance document likewise would significantly reduce the compliance burden associated with the draft. 4. Finally, Seattle requests technical justification by established for continent-wide application of a 1500 fault MVA threshold. Once established in a Standard, a technical justification will be required for any change; as such technical justification should be provided beforehand to establish the value as correct and appropriate. This value may be correct and appropriate for the NPCC area, but has not been justified in other regions. It may well be correct and appropriate, but a justification has not yet been provided.

Response:

1. The need for the development of a standard rather than criteria or a guideline for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:

"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."

The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.

The Lower Violation Risk Factor was selected for the PRC-002-2 requirements because they do immediately affect the real-time electrical state or capability of the bulk electric system.

2. The bus identification process provides a consistent method to be able to define for what BES Elements data needs to be captured.

3. PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.

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4. The 1500 MVA value was arrived at based on three phase fault MVA data collected from industry from the June 5, 2013 Informal Request for Information posting.	
PPL NERC Registered Affiliates	See comments 3a-3c below. 3a. The Guidelines and Technical Basis Section of the standard states in the first paragraph on p.33 that, "SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data." The next section (Guideline for Requirement R2) states however that "Generator Owners are included in this requirement [for SER data] because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus." All generator output breakers connect eventually to the transmission system however, nor is it clear why the aforementioned lack of tripping time reliability for GO sequence-of-events monitoring would apparently apply in some cases (GO SER data mandatory) and not in others (GO SER data not required). 3b. The Guideline for Requirement R3 on p.33 states that "Generator step up transformers (GSU) are excluded from the above based on the following:- Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system.- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed. The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data." This seems to fully exclude GOs from fault recording obligations, so why are GOs obligated in R3 and R4 to have FR data? 3c. Comments 3a and 3b above gain emphasis from the circumstance that it is expected that the Guidelines and technical Basis Section of the draft standard will be deleted if and when PRC-002-2 is voted-in and approved by FERC. That is, the logic by which GOs are sometimes in and sometimes out will be even more obscure than it is now.

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	3d. The requirements for GOs to "have" SER (R2), FR (R3 and R4) and DDR (R7) data are understood to mean that they do not need to own this equipment, and it would do just as well to have an agreement with the TO to fulfill the PRC-002-2 requirements if and where the TO already has DME on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002-2. There should be a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install DME or, where the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comments above.
Response: **3a. While DDR data more accurately reveals how a generator is behaving, SER data for breakers connected to a transmission system bus is useful in determining fault clearing times, and identifying interrupting device problems. The intent is to have SER data for generator output breakers connected directly to a Transmission Owner's Bus. SER and FR data is needed to analyze "fast" disturbances on the BES, not the slowly evolving disturbances captured effectively by DDR. The wording of the Guideline for Requirement R2 was revised.** **3b. Requirements R3 and R4 apply to GOs to ensure that data is collected for transmission system BES Elements a GO might own.** **3c. The Guidelines and Technical Basis Section stays with the materials for the standard after the standard is approved by FERC. The Standard Drafting Team is revising the Guidelines and Technical Basis Section to ensure consistency.** **3d. As stated, the standard does not deal with "how" data is recorded, but "what" data is recorded. Because of the importance of generator response to system disturbances, the GO is needed to be included in this standard. A statement has been added to the Introduction of the Guidelines and Technical Basis Section to reinforce the "what" versus "how."**	
SPP Standards Review Group	Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DM SDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. In some places in the documentation three-phase is hyphenated and in others it is not. While we think it should be, we encourage the DM SDT to be consistent. 'Disturbance' is defined in the NERC Glossary and depending upon its usage should be capitalized. The DM SDT needs to be

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	consistent with its format. In the 2nd line of M3, insert 'that' in between 'data' and 'is'. In the 3rd line of the 1st paragraph in the Rationale Box for R5, it would be appropriate to use BES rather than spelling out Bulk Electric System. Add a hyphen to 'high-' in the 3rd line of the Rationale Box for R7. This is consistent with usage throughout the rest of the documentation. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. Also, in the next to last line of the last paragraph 'disturbance recording' is capitalized. It is not a defined term in the NERC Glossary and shouldn't be capitalized. This change needs to be made throughout the documentation. In the 6th line of the Rationale Box for R12, 'entity' should not be capitalized. In the VSLs for R2, insert 'Owner' between 'Transmission' and 'or' for consistency throughout the VSLs for the other requirements. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3. Proceed to Step 9.''Disturbance monitoring' is capitalized in the Introduction of the Guidelines and Technical Basis Section. Since it is not a defined term in the NERC Glossary, it shouldn't be capitalized. Modify the next to last line of the 1st paragraph in the Guideline for Requirement R1 to read '...voltage and current for individual circuits allow precise reconstruction of events of both...' Change 'disturbance' to 'disturbances' in the next to last line of the 2nd paragraph. In Item 6 on Page 32 (clean version) of the same section, insert 'to those' between 'buses' and 'with'. In the 6th bullet under Item 8 on the same page, change 'Owners'' to 'Owner's'. Hyphenate 'in-effect' in the 1st line of the 2nd paragraph of the Guideline for Requirement R3. Modify the 1st line of the Voltage Recordings section on Page 34 (clean version) to read 'Voltages are to be recorded at applicable BES buses. Note that Requirement R3 calls for the...'Delete the 's' on 'meets' in the 2nd line of the 1st paragraph of the Guideline for Requirement R4. Change 'captured' in the 1st line on Page 35 to 'captures'. In the 2nd line of the same paragraph, set the phrase 'when time synchronized to a common clock' off with commas. Delete the last sentence of the 1st full paragraph on Page 36 (clean version). It is a duplicate. Insert an 'a' between 'after' and 'fault' in the 1st line of the 1st paragraph under Guideline for Requirement R6.Replace 'has' with

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	'with' in the 3rd line of the 1st full paragraph on Page 37 (clean version). Near the end of that same line, there appears to be an extra space between 'Bus,' and 'would'. Skip a line and hyphenate 'in-service'. Capitalize Real Power and Reactive Power here and in the last paragraph before Guideline for Requirement R7. Add a hyphen to 'high-' at the end of the 1st line under Guideline for Requirement R7.Hyphenate 'short-term' in the 2nd line of the 1st paragraph under Guideline for Requirement R9. In the 4th line of the 2nd paragraph, insert an 'a' between 'in' and 'sampled'. Capitalize 'Requirement R1' and 'Requirement R5' in the 3rd line of the 1st paragraph under Guideline for Requirement R11. Delete the 'a' in front of 'Day 1' in the 6th line of the 3rd paragraph under Guideline for Requirement R11. Insert an 'and' and delete the 'it' in the 2nd and 3rd lines of the 2nd paragraph on Page 40 (clean version). That portion of the sentence should then read '...Transient Data Exchange and is well established in the industry.' Split the 2nd sentence of the 3rd paragraph on Page 40 (clean version) into two sentences such that it reads '...Naming Time Sequence Data Files. The first version was approved in 2007.' In the 4th line of the 3rd paragraph on Page 40 (clean version) replace 'was' with 'were'. Hyphenate 'out-of-service' in the paragraph under Guideline for Requirement R12. Also, there appears to be an extra space between 'develop' and 'a' in the 10th line of the same paragraph.
Response: The wording and punctuation in the standard has been reviewed, revised, and made consistent. Terms using "calendar date" have been hyphenated throughout as well as step-up and 30-cycle post-trigger. The DMSDT capitalized Disturbance as well as System and Transmission throughout the standard where appropriate. The other grammar and syntax changes that you suggested were incorporated into the standard.	
PNM	Suggested rewording of R12 to clearly state submission of CAP is required. "...develop a timeline for restoration and submit a Corrective Action Plan (CAP) to Regional Entity."
Response: The wording of Requirement R12 was revised to specify submittal of a CAP as well as implementation of the CAP.	
Tacoma Power	Tacoma Power disagrees with the need for this standard and believes there are more cost effective alternatives for acquiring the data necessary for event analysis. However, assuming that this standard will likely proceed to approval, we are providing both comments for improving the draft

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	standard and an explanation for why we believe this standard is not the appropriate method to address the perceived needs. a. Under Measurement M3, change "...of FR data is..." to "...of FR data that is..." b. Under Measurement M11, change "...evidence (electronic or hard copy) data..." to "...evidence (electronic or hard copy) that data..." c. What if FR, SER, or DDR equipment is taken out of service for maintenance and/or testing. Could this result in an automatic violation of Requirement R11, Part 11.2? Or, should this be treated like a failure under Requirement R12? d. In Attachment 1, Step 7, for cases in which the list has 11 or fewer BES buses, change "...at the BES buses with..." to "...at the BES bus with..." e. Please confirm that only the channels that trigger need to be provided upon request and that no cross-triggering between FR or SER is required. f. Requirements R3 and R4 should require the capability to record data rather than requiring data. g. The VSLs for Requirement R10 should be based on the number of missed electrical quantities rather than the number of BES buses. Otherwise, please provide guidance on how a substation with several relays correctly time stamped but one relay with an incorrect time stamp should be treated. h. Requirement R10 should be modified to have SER timestamping to +/- 40 milliseconds while maintaining the FR and DDR timestamp of +/- 2 milliseconds for two reasons. First, the breaker position indication using 52a or 52b contacts can be different than the main contacts opening and ultimate current interruption by more than 2 cycles. Typical, 52a vs 52b contacts are at least Â½ of a cycle apart. Timestamping the relay input to 2 milliseconds will not actually indicate the state of the power system. Second, SEL 300 series relays timestamp SERs to the nearest quarter cycle, so a large number of installed relays would not meet the requirements for SERs. These relays do timestamp the FR to the specified accuracy, just not the SER.Alteratives to this draft standard:The 2003 outage report outlined major deficiencies with event recording, but the data recording technology has dramatically changed in the last decade. Even though no standard was in place

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	specifying data recording, utilities have been installing GPS time stamped event recording based on business drivers. As outlined during the CEAP report, the labor for event report alignment was reduced from 4,400 person-hours for the 2003 outage to only a week for the 2011 southwest outage. Although further reductions in event analysis SME hours would result from this standard, the compliance SME hours would dramatically increase and result in overall higher costs. As outlined in the CEAP report, most utilities already have event recording in place, or are going toward recording as part of multifunctional equipment installations. Therefore, ignoring automated event collection, the only costs that should be considered are due to the increment burdens of documenting compliance with this standard. Instead of this standard, we believe that a NERC guidance document on event reporting best practice would be equally effective while requiring very little compliance burden. In other areas, NERC is moving away from standards that require zero defects in high volume tasks. This standard requires 100% accurate time stamping of 100% of a small portion of elements, but then ignores 80% of BES buses. On a voluntary basis, we have approximately 50% of elements monitored. Thus if we supplied only the event reports required by the standard, the coverage of our system would go down dramatically. In order to meet the zero defect policy of this standard, we will have to redirect efforts from actual event analysis to documentation of event recording capability. If data recording is implemented as a standard instead of a best practice guideline, it sets the minimum bar instead of the optimal goal. Most utilities already have at least a marginal level of recording capabilities. We would prefer NERC to aim higher. The best event records occur when all data channels at a substation are recorded for a trigger on any channel for any kind of transient, including frequency or overvoltage. This level of recording is impractical to require as a standard but is already in place for many utilities. For an enforceable standard, we agree that undervoltage & current are the only reasonable triggers to require.We are concerned that the SDT appears to have based installation cost assumptions on the premise of using data stored locally on relays. If this is an enforceable standard with a zero defect requirement, utilities are in essence forced to automated event collection from relays in order to guarantee zero defects. This automated event collection then brings in large costs for communications, and for applying CIP standards to those communications. If this were a best practices document, or allowed some data gaps, local relay storage would be a reasonable assumption.

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Response: **a. The wording of Measure M3 has been revised.** **b. The wording of Measure M11 has been revised.** **c. The Rationale Box and Guideline for Requirement R12 explain that any recording capability outage greater than 90 calendar days is treated as a failure of recording capability.** **d. The wording in Attachment 1, Step 7 has been revised.** **e. The triggered channel data will be requested after a system disturbance. The appropriate triggering implemented to capture the desired data is the intent of PRC-002-2.** **f. The standard is about "what" data is recorded, not "how" it is recorded.** **g. The VSLs correctly reflect the necessities for correctly collecting data. The time stamp associated with the data collected for a BES Element must be correct.** **h. PRC-002-2 is about "what" data is recorded, not "how" the data is recorded. Requirement R10 was revised to address synchronization to Coordinated Universal Time, and synchronized device clock accuracy to +/- 2msec to reflect equipment realities. It is understood that there are many entities that have the capabilities called for in the standard in place already, but the intent of the standard is to ensure there are no gaps. Having recording capability beyond what is required in the standard is an engineering, planning, and operational plus. It is difficult, if not impossible, to quantify the costs of implementing lessons learned from events analysis made possible by the availability of system data.**	
~~City of Tallahassee~~	~~TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.~~
~~City of Tallahassee~~	~~TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.~~

Organization	Question 3 Comment
City of Tallahassee	TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Response: The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: **"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.** **A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."** **The Disturbance monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.** **Event analysis allows industry to take steps to prevent recurrence of an incident. This standard will ensure that there are no gaps in the data, and sufficient and complete data is available for this analysis. DDR is especially useful in analyzing generator performance and response. It is difficult, if not impossible, to quantify the costs of implementing lessons learned from events analysis made possible by the availability of system data.**	
Colorado Springs Utilities	Thank you SDT for your efforts we voted negative for the following reasons:This standard brings 20% of our buses into scope, which means it will bring 20% of just about everyone's buses into scope (some large companies could have hundreds of buses included). Is that really the SDT's intent? It sounded like the SDT is not expecting it to be that big of an impact. The MVA threshold needs to be re-visited to prevent excessive, unmerited impact. We do not believe that it is logical to include a bunch of buses from smaller entities that just barely cross the threshold and then only include the top 20% of companies with buses having orders of magnitude greater short circuit duty. How can the inclusion criteria be modified to make sure that we capture the appropriate points of the system based on actual risk and impact to the BES? The current criteria is too inclusive and too

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	generic - which impacts industry unnecessarily without getting the desired result.Thank You!Bottom line, IMO, the technical basis for this standard is flawed.
Response: After a review of the data received from the June 5, 2013 Request for Information, the Drafting Team decided upon the numbers used in the standard, and that the implementation of the standard to those identified BES buses and BES Elements would provide adequate system Disturbance Monitoring. The recording capabilities would provide adequate data to reconstruct a major system incident, and allow an analysis that could prevent a future recurrence. Note that the standard allows an entity to determine quantities.	
JEA	The 1500MVA threshold is too low and needs to be increased.
Response: The Standard Drafting Team is made up of members from different size entities, and received input from the June 5, 2013 Request for Information posting from across the continent to determine the numbers and philosophies used in Attachment 1.	
SERC Protection and Controls Subcommitee	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for your comments.	
Northeast Utilities	The preparation and accuracy of the redlined version and this unofficial comment form is lacking and promotes confusion. The redlined version does not effectively show many of the numerous redlined changes from the last posting, including nearly all of R5. The comment form description of the changes to the implementation plan does not agree with the standard. From above description of changes:"The schedule for implementation is now to be at least 50% compliant within three (3) years following notification of the list, and 100% compliant within five (5) years following notification of the list. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within five (5) years following notification of the list."From the actual standard posted for comment:Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective

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	Date. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within four (4) years of the Effective Date. Page 11, Requirement 5 states "Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder recording (DDR) data is required, ..."While page 5 (blue explanation box& Mapping document) still states "Rationale for Functional Entities: The Responsible Entity - the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection - has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.
Response: There were problems encountered in finalizing the clean and redlined versions of PRC-002-2 and its Implementation Plan for the posting. Regarding the implementation for requirements R2-R4, R6-R11, **"Entities shall be at least 50 percent compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.** **Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.** **Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."** **Because DDR is useful for analyzing slowly evolving widespread system disturbances, the Responsible Entity (PC or RC), is in the best position to determine from where DDR data should be captured.** **The standard and its Rationale Boxes and Guidelines have been reviewed for consistency and revised accordingly.**	
Seminole Electric Cooperative, Inc.	The three-phase short circuit level minimum of 1500 MVA at BES voltage levels is low. As a result, entities must sort through large numbers of buses when only the top 11 would need to be selected. Buses at low three-phase fault current are not typically conducive to disturbance monitoring equipment. For example, a 345 kV bus that carries 3000 amps (normal flow) would be a candidate for PRC-002 even without applying a three-phase fault. It would seem that a threshold of 10,000 MVA is technically justifiable, since most BES stations that have over 10,000 MVA of available

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	three-phase fault current are candidates for being critical facilities that would benefit from disturbance monitoring equipment or already have such equipment installed. This would also reduce the number of buses that the TO needs to review.There is uncertainty regarding the technical justification for the “11” BES buses that is listed in Step 3 of Attachment 1. Requirement R8 does not clearly identify the data storage requirements for DDR with continuous recording capability. A 3-year period of continuous recording data per DDR location is too onerous. DDR continuous recording capability should be a minimum of 10 days per site. DDR recording(s) retained as evidence should strictly be limited to event-triggered recording by a system disturbance and where the RC, RE, or NERC requests data for the event within the 10-day time frame.Requirement R11.4’s required conformance with IEEE Standard C37.111-”2013” is too onerous. This Requirement disqualifies the majority of FR and DDR equipment presently deployed. Seminole recommends revising the Requirement to require the use of IEEE Standard C37.111-”1999” or later.
Response: The Drafting Team is made up of members from different size entities, and received input from across the continent to determine the numbers and philosophies used in Attachment 1. The numbers chosen were the most appropriate to use after reviewing the data on hand from the June 5, 2013 Request for Information. Eleven were chosen as the number of buses specified in Step 3 of Attachment 1 after review of the data received from the June 5, 2013 Request for Information from industry, and the judgment of the Drafting Team from Real-time experiences. **The intent of the retention period is for the entity to retain the data that has been requested for a triggered disturbance only.** **Requirement 11 Part R11.2 has been revised.** **Requirement 11 Part R11.4 was revised to read C37.111-1999.**	
Pepco Holdings Inc.	Under requirement R11.2, suggest modifying the wording to the following: The recorded data will be retained for a minimum of 10 calendar days.
Response: Requirement 11 Part R11.2 has been revised to clarify that data retention is for a disturbance.	

Organization	Question 3 Comment
City Utilities of Springfield, MO	We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. To provide a context for our comment, our system has a peak load of 800 MW serving approximately 110,000 customers in a service territory covering 320 square miles (less than one county) with local generating capacity of 1100 MW. This is a very compact system containing a relatively small geographic footprint with 17 BES buses as defined within this draft standard. All of these 17 BES buses have fault MVA above the 1500 MVA threshold, ranging from 8,000 MVA down to 2,900 MVA with a median value (bus 6 out of the top 11) of 5,800 MVA. The top 10 BES buses on our system all have a fault MVA above 5,000. This PRC-002-2 draft Standard will require us to have FR data for 4 buses (20%) overall. The top 2 BES buses (10%) where FR data would be required will be electrically less than 2 miles apart. The other 2 buses (additional 10%) would be located 25 miles or less electrically from the first 2 buses regardless of how we elected to determine these locations. All this data will be electrically concentrated in a small geographical area, which doesn't appear to lead to a wide-area view of the overall BES. Additionally, several of the above mentioned buses have only two (2) BES sources (Distribution buses with only 2 transmission lines connected) or tapped buses with Distribution transformer(s) and no transmission breakers. Are these buses really important to the BES in the context of DME data? It seems the PRC-002-2 R1 Attachment 1 method only serves to unnecessarily inflate the number of BES buses on which the overall percentage of required locations will be calculated. We recognize the difficulty the SDT had in determining the appropriate coverage for FR data, but contend that a fault MVA threshold closer to 4500 MVA and an overall coverage percentage of 10% is adequate. This would still result in our system having FR data at 2 buses which could be electrically separated by approximately 25 miles. Additionally, we believe buses with only limited sources from the BES should be excluded out-of-hand by some other "test" mechanism within the Attachment 1 document or some other vehicle. Regarding R3: 1) Is it the intent of the Standard that FR data is to be determined for all currents defined on all Elements connected to a selected bus for any single fault on any Element connected to the bus? (i.e. if using digital relays for FR, do relays on each element (line or transformer) need to trigger for faults on any element connected to that bus?)

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	2) What are the expectations for faults and/or disturbances located remotely from the selected bus - how sensitive are they expected to be? In reality, are these FR devices expected to be a lower level disturbance recorder? 3) If data is expected to be available for conditions other than just faults, the data should not be classified as Fault Recording data or at least further definition/clarification should be provided. 4) Some of the discussion in the rationale box for R3 seems to suggest the FR data be used for fault analysis, as it applies to determining correct and incorrect breaker operations - Misoperation determination. In the case of installed modern microprocessor relays, the protective relay(s) should be able to determine the nature of the fault, the elements that operated, fault location, voltages and currents and many other particulars associated with a fault. Generally, FR is an unnecessary addition of equipment in these situations from the perspective of fault analysis to determine the correctness of protection system operation. 5) Regarding R4: We propose changing the 30 cycle post trigger record length in the first bullet under R4.1 to a total record length of 30 cycles. The current wording requires a 32 cycle minimum total record length. We believe the 30 cycle total record length better matches existing microprocessor relay functionality for those that may wish to employ them in this fashion.

Response: The Standard Drafting Team is made up of members from different size entities, and received input from across the continent to determine the numbers and philosophies used in Attachment 1. The numbers chosen were the most appropriate to use after reviewing the data on hand. The Standard Drafting Team recognized that load dense areas' data may be required from stations that are only blocks apart. Note that the Requirements say to be able to determine--if data can be determined for an Element, the data does not have to be captured for that Element. To clarify what buses need consideration, From Attachment 1, Step 1:

"For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus."

1. Requirement R3 stipulates that data is to be captured for "... each of the BES Elements it owns connected to the BES buses identified in Requirement R..." Sensitivity of the triggering for data capture depends on the parameters of the BES.

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2. Data has to be captured for the identified BES Elements. Again, the sensitivity of the triggering depends on engineering judgment and the parameters of the BES. The standard is about "what" data is recorded, not "how" it is recorded. FR data conveys information different from DDR data, and is not intended to replace DDR data. **3. DDR would capture "slowly" evolving system conditions and disturbances that might not involve faults.** **4. FR data has been used successfully in rapid system restorations following multiple feeder tripouts to help expeditiously determine the faulted Element, and thus allow restoration of unfaulted facilities. The data provided by microprocessor relays may be used to satisfy Requirement R3.** **5. The Standard Drafting Team has revised the total record length to 30 cycles as suggested.**	
Kansas City Power & Light	We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability. Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DMSDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.'

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Response: The rationale box for functional entities was revised to clarify the meaning of the use of Responsible Entity in PRC-002-2. **The text was reviewed and revised to ensure consistency in the use of hyphenation, punctuation and grammar.** **The wording in Requirement R8 was revised.** **The wording in the rationale box for Requirement R11 was revised.** **The wording for Attachment 1, Step 7 was revised.**	
Idaho Power Co.	When a relay is used to capture FR data rather than a digital fault recorder, Requirement R4.1 would necessitate a relay record length of at least 32 cycles under R4.1-bullet 1 or multiple triggers under R4.1-bullet 2. Our wide variety of relay types support records of 15, 30, 60, or 180 cycles. Current practice and preference is to use a record length of 30 cycles, trigger inclusive, which was chosen to balance the amount of information in a single record while still providing the capability in the relay to save multiple records. The 32 cycle requirement would force the use of 60 cycle event records. While many of our relays are capable of this, the practice may lead to missed event records impacting our ability to search for misoperations under PRC-004.Multiple triggering has already caused events to be missed in our system due to the limited capability of some legacy relays. A change to a record length of 30 cycles including the 2 cycles of pre-fault trigger would fit within our current practice which mitigates our capture problems.
Response: The Standard Drafting Team discussed changing the overall record length of 32 cycles. It is commonly employed in industry, and is not an unreasonable specification nor difficult to implement.	
Florida Municipal Power Agency	While FMPA appreciates the efforts of the SDT to address many of the specific comments received, FMPA's position remains that a standard is not justified for Disturbance Monitoring. We believe that Disturbance Monitoring is better addressed through guidelines than through a standard. The system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays and phasor measurement units (PMUs) prevalent throughout the system. The justification for this standard is primarily based on the decade old Blackout Report and does not take into account the changes in system

Organization	Question 3 Comment
	equipment since then. This justification was highlighted by the SDT's response to FMPA's prior comment about a standard not needed. SDT Response: "(1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:..."Additionally, it should be noted that in the Executive Summary of the Cost Effectiveness Analysis Process (CEAP) Pilot for this project, the following statement was made: "The majority of CEA respondents believed the standard's potential immediate reliability benefits were minimal." So, with this CEAP observation along with the low approval rating of 43.29%, there is clearly some significant stakeholder concern with the justification for this standard.In light of the Paragraph 81 Project, the industry is supporting reducing and consolidating the amount of requirements. This standard meets several Paragraph 81 Criteria used to identify requirements for retirement including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. There are 12 requirements and over 20 sub-requirements in the current PRC002-2 draft. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. While we do not believe the standard is needed, we strongly recommend that if this project goes forward, that the drafting team revise this standard to two or three requirements. We point out that the NERC Rules of Procedure have a detailed section on Disturbance Response Procedures - Appendix 8.While we recognize that the SDT has limited latitude in eliminating a project or veering from the SAR, we suggest that the Standard Committee revisit the justification for this standard and at a minimum review the scope and prescriptiveness of the detailed requirements in light of the Paragraph 81 guidelines.

Response: The Standard Drafting Team realizes that improvements have been made to Disturbance Monitoring technology since the 2003 Northeast Blackout. That does not guarantee universal implementation, thus necessitating the need for the standard.

PRC-002-2 addresses "what" data is recorded, not "how" the data is recorded. This approach eliminates the complications that might arise from the technological advances being made to record the data.

The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better Real-time system management (Real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.

Organization	Question 3 Comment
Xcel Energy	Xcel Energy engineers have conducted a test application of the selection criteria in Attachment 1, and have concerns that some locations are identified but provide little or no value (e.g. situations where fault recording is required for busses at both ends of a short line and one of the busses has only two sources (see diagram provided separately via email to the NERC SDT Coordinator for this standard)). We recommended an 'exception' written into the requirements with the Responsible Entity (or RC or Regional Entity) concurrence. In R5 - please clarify if the IROLs are those established by the TP, PC, or RC. (Also note that RC established IROLs may be in the operating horizon with little or no time for entities to actually install equipment).R12 should be reworded to state "...or develop and submit to the Regional Entity..." and end after "...(CAP)." R12 - is it inferred that entities can conduct maintenance on these devices (ie - out of service) as long as they meet the 90 day requirement? If so, consider making that clear.
Response: In developing Attachment 1, the Standard Drafting Team recognized that electrically close bus locations (referring to the diagram provided by Xcel Energy) would possibly diminish the overall "needed" number of locations to capture adequate SER and FR data for because of the possible concentration of load. The Standard Drafting Team considered this, and is addressed in Steps 7 and 8 of Attachment 1. **Because Requirement R5 pertains to the Responsible Entity (as used in the standard), the Responsible Entity is responsible for establishing the IROLs.** **The wording of Requirement R12 and its rationale box have been revised. Entities can conduct maintenance as long as the 90 calendar day requirement is met. That is also explained in the Guideline for Requirement R12.**	

ADDITIONAL COMMENTS:

Calpine Corporation
Hamid Zakery

. I had trouble with submitting comments. We appreciated the hard work demonstrated by the SDT and NERC members with this draft standard. I voted no for the following reasons:

1. Requirement R1 of the draft standard states each “Transmission owners shall identify BES buses for which SER and FR data is required….”. Do elements connected to these bused include generators? We believe examples by illustration can provide much needed clarity.

Response: BES Elements connected to the identified BES buses do include generators. Generator Interconnections are not required to have FR, but generator breakers directly connected to an identified BES bus need to be included in SER data capture.

2. Are FRs required at all generating stations that are connected to the BES regardless of size and connected BES voltage? We believe installation of FR at generating facilities connected to voltages <200 kv is too aggressive and will impose significant resources requirements without contributing much benefit for the BES reliability. Has the feasibility of installing DME at a generating facility with one or two units to monitor 4-8 data points @ voltages <200 Kv been evaluated. While members of vertically integrated utilities can utilize a DME for both their transmission and generation data points, a non-vertically integrated generator owner is required by draft standard to install a DME for 3-4 data points. We suggest FR installation BES voltages greater than 200 kv with single generator rating of 500 MVA and an aggregate generation of 1500 MVA at a single site.

Response: FR is not required for generators and their interconnections to the BES. PRC-002-2 addresses “what” data is recorded, not “how” it is recorded. Requirement R3 specifies that the electrical quantities can be “determined.” The Rationale Box and Guideline for Requirement R3 have been revised and provide clarification.

3. The initial standard drafting team had performed studies and was recommending FR and DDR installation at 345 kv and higher voltages based on specific requirements that supported improving BES stability and reliability. We ask that current SDT to demonstrate basis/rational for the DME (FR & DDR) need at all BES voltage levels. A rough breakdown statistics on number of FR that will be required by R1 and R3 of the draft standard and implied reliability benefit by each requirement at each BES voltage level will be very beneficial. Also, several NERC Regions had previously developed DME criteria with FR and DDR requirement at >200 KV BES voltage levels. The Only region will region with DME requirements at all BES voltages was NPCC. Has the SDT team discussed DME requirements by Region or interconnection?

Response: The Standard Drafting Team is aware of the requirements in the Regions. PRC-00-2 is designed to address the capturing of data, and having adequate data available to be able to determine disturbance quantities. PRC-002-2 addresses "what" data is captured, not "how" it is captured.

Portland General Electric Company
Angela Gaines

Portland General Electric appreciates the drafting team's efforts regarding the project. After additional review, PGE has no concerns regarding the proposed standard. The negative votes were cast in error.

Response: The Standard Drafting Team thanks you for your comment.

END OF REPORT