NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on PRC-002-NPCC-1 — Disturbance Monitoring

The Regional Reliability Standards Working Group thanks all commenters who submitted comments on the second posting of the Regional Reliability Standard PRC-002-NPCC-1— Disturbance Monitoring. This standard was posted for a 15-day public comment period from January 19, 2010 through February 3, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 7 sets of comments, including comments from 31 different people from approximately 16 companies representing 5 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
8.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Greg Mason	Dynegy Generation	NPCC	5

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
15.	Bruce Metruck	New York Power Authority	NPCC	6										
16.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5										
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1										
18.	Saurabh Saksena	National Grid	NPCC	1										
19.	Michael Schiavone	National Grid	NPCC	1										
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3										
21.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10										
2.	Group	Mike Garton	Electric Market Policy		X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jalal Babik	Dominion Resources, Inc.	RFC	3
2.	Louis Slade	Dominion Resources, Inc.	SERC	6

3.	Group	Denise Koehn	Bonneville Power		X		X		X	X				

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

4.	Individual	Michael R. Lombardi	Northeast Utilities		X		X		X					
5.	Individual	Martin Bauer	US Bureau of Reclamation						X					
6.	Individual	Dan Rochester	Independent Electricity System Operator			X								
7.	Individual	Richard Kafka	Pepco Holdings, Inc.		X		X		X	X				

1. Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	
Electric Market Policy	No	While we understand NPCC's concern with postponement until a NERC standard is approved, it is unreasonable to ask owners to commit resources to meeting a regional standard which could be replaced by a continent wide standard by 2011.The third draft NPCC Regional Reliability Standard PRC-002-NPCC-1, Disturbance Monitoring, was posted on the NPCC website on September 9, 2009 for comments through October 24, 2009. Subsequently, on October 1, 2009, the second draft of the NPCC regional standard was posted on the NERC website for industry review through November 16, 2009. The concurrent (i.e., NPCC and ERO) posting of a third draft regional reliability standard is not specifically allowed by the NPCC Regional Reliability Standards Development Procedure (RRSDP). In fact, Step 6 (Solicit Public Comment on Draft Standards) specifically states "Final draft standards will be concurrently posted on the ERO website for comments." One could argue that a regional reliability standard still in the NPCC open process comment phase until October 24, 2009, is not a final draft standard and posting on NERC's website is premature and violates fair due process.
Response: The 2003 Blackout Investigation concluded that there was insufficient disturbance monitoring equipment installed to analyze the event, which emphasized the importance of having a standard in place to address the problem. NPCC thereby initiated development of PRC-002-NPCC-01, which is more stringent than the current drafts of the NERC continent-wide standard. After the NERC Standard is developed, it will be compared with PRC-002-NPCC-01, and any redundancies removed. Even with the ultimate development and approval of the continent-wide standard, the combination of the continent-wide standard and PRC-002-NPCC-01 will include the provisions in today's PRC-002-NPCC-01. As pointed out, drafts of the Standard were posted concurrently by NPCC and NERC. Because the draft had gone through two prior postings, the Drafting Team felt that this would be the final draft prior to going to ballot. The NERC Regional Reliability Standards Evaluation Procedure in Step 2--Sequence Considerations states: "…the region may request this be performed concurrent with the anticipated final public comment period…" not mandating the final version be posted.		
Bonneville Power	Yes	
Northeast Utilities	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
Pepco Holdings, Inc.	Yes	

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	
Electric Market Policy	No	
Bonneville Power	No	
Northeast Utilities	No	
US Bureau of Reclamation	No	
Independent Electricity System Operator	No	
Pepco Holdings, Inc.	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	
Electric Market Policy	No	
Bonneville Power	No	
Northeast Utilities	No	
US Bureau of Reclamation	No	
Independent Electricity System Operator	No	
Pepco Holdings, Inc.	No	

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	
Electric Market Policy	No	
Bonneville Power	Yes	BPA believes the burden is due to requiring more monitoring equipment based upon the RC requirement. Why the RC and not the RE (which coordinates members)?
Response: The RC requirement for disturbance monitoring equipment does not place a burden on competitive markets within the interconnection. The requirements for Disturbance Monitoring equipment were developed to ensure that adequate information for system disturbance analysis would be available. Requirements were directed at the Reliability Coordinators rather than the Regional Entities because of the international composition of NPCC's membership which requires a need for flexibility with provincial RCs. Also, RCs have more intimate technical and operational knowledge of their systems than does the RE.		
Northeast Utilities	No	
US Bureau of Reclamation	Yes	Comments relating to PRC-002-NPCC-1 â€• Disturbance Monitoring Definitions:"Generating Plant: One or more generators at a single physical location whereby any single contingency can affect all the generators at that location." This definition appear to be inconsistent the definition in the NERC Glossary for Facilities. The definition makes a generator comparable to a facility. The Definition needs to be prefaced with the words "A facility with""Protection Group: A fully integrated assembly of protective relays and associated equipment that is designed to perform the specified protective functions for a power system element, independent of other groups."The term appears very similar to the term in the NERC Glossary for Protection Systems; however, the definition is not consistent and may cause confusion. The definition does not specifically include battery systems or DC circuits as called out in the existing NERC Glossary Definition. "Protective Relay: A relay that detects a power system fault or abnormal condition and initiates appropriate control system action."This definition is tailored to transmission facilities. The definition eliminates devices used to protect generator by using the term "power system". This creates a conflict with the protective system devices covered under PRC004. By this definition, any there can be no protective device operations when the unit is operated disconnected from the power system. It is suggested that the words "power system" be removed. R1. "Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System

Organization	Yes or No	Question 4 Comment
		(DCS) or part of Fault recording equipment."The requirement violates the limitation imposed by the Energy Policy Act of 2005 which was structured to ensure reliability of the existing bulk electric system. The Act specifically limited actions ''(3) The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cyber security protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. [emphasis added]." The requirement cannot require the addition of the equipment but rather place a requirement on th equipment if the equipment is added by the owner. 1.2 "Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions"There is no explanation as to which breakers are required to be monitored. Clarity is needed to ensure that the standard is not interpreted to include station service breakers.R5. "Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element..." This requirement must contain the caveat supplied in R4 which excludes the requirement if the Transmission owner provides the fault measurement.R6. "Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities:" This requirement must contain the caveat supplied in R4 which excludes the requirement if the Transmission owner provides the fault measurement.
Response: The Generating Plant definition in the Standard is independent of the NERC Facility definition, the word accentuating the independence being "operates" in the NERC definition. Generating Plant refers to "One or more generators at a single physical location whereby any single contingency can affect all the generators at that location." Adding protective relays, protection group, protection system or similar language would be beyond the scope of the Standard. The 2003 Blackout Investigation concluded that there was insufficient disturbance monitoring equipment installed to analyze the disturbance. This Standard ensures that there will be adequate resources in place for event analysis, and does not require adding new transmission or generation capacity. For what equipment is to be monitored, as stated in the Purpose: "…All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements." It is implicit that the wording stipulated in R4 regarding fault recording capability already provided by the Transmission Owner applies to the subsequent fault recording requirements R5, and R6. If the Transmission Owner has sufficient recording capability then the Generator Owner need not provide.		
Independent Electricity System Operator	No	
Pepco Holdings, Inc.	No	

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard
- The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard
- The proposed regional difference is necessitated by a physical difference in the bulk power system.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	Yes	
Electric Market Policy	Yes	In FERC Order No. 693, the Commission expressed concern regarding the potential for the fill-in-the-blank standards to undermine uniformity. The Commission further notes, "the ERO should consider whether greater consistency can be achieved in this Reliability Standard." While the proposed standard does meet at least one of the criteria, Dominion is of the opinion that NERC is potentially creating needless regional differences by not having a national standard on DME in place before the regional standard debate on DME is opened.We recognize that NERC is developing a continent-wide reliability standard per Project 2007-11 PRC-002-2, Disturbance Monitoring and Reporting Requirements. Unfortunately, this standard has not gotten the priority within NERC that it deserves. Hence, the development of a regional reliability standard seems premature at this point and Dominion believes that it would better serve the industry to wait until the continent-wide standard is fully vetted via the open process. NERC would have better served its constituents if it had rescinded BOT approval of those standards that FERC didn't approve or remand in Order 693. At least then entities would not feel compelled to meet the requirements of those standards. Dominion requests that the NERC BOT rescind approval of those standards that FERC did not approve or remand in Order 693.
Response: This Standard was developed to address Disturbance Monitoring equipment that is necessary for the reliable operation of the power system by providing the tools to analyze system disturbances, and prevent their recurrence. This Standard is more stringent than the current drafts of the NERC continent-wide standard. After the NERC Standard is developed, it will be compared with PRC-002-NPCC-01 and any redundancies removed. The NERC Regional Reliability Standards Working Group is also reviewing the regional standards, and providing guidance to the Regions for regional standard consistency.		
Bonneville Power	Yes	Additional Comments on this Standard:R1 - a) BPA believes that R1 runs together too much; use the word "either" to help spell out options. Also, there is a hidden interaction with R16 requiring 1 millisecond timing that current SCADA or DCS systems are not operating at. This conversion would involve major expenses. b) BPA believes 1.1 means a "single" circuit breaker, does it? Perhaps spell out more clearly.c) BPA disagrees

Organization	Yes or No	Question 5 Comment
		with 1.2.2 - This will involve much expense at older plants. GO/GOP comment: The requirement violates the limitation imposed by the Energy Policy Act of 2005, which was structured to ensure reliability of the existing bulk electric system. The Act specifically limited actions ‘‘(3) The term ‘reliability standard’ means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. (The term includes requirements for the operation of existing bulk-power system facilities, including cyber security protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, . . . but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity. [emphasis added] The requirement cannot require the addition of the equipment, but rather place a requirement on the equipment if the equipment is added by the owner. R2. - a) BPA believes the installation criteria reference should be corrected to R4 (not R3) (editorial - it appears R3 was an insert).b) BPA believes that R 2.4 intent is generation "line" interconnections, is it? Perhaps spell out more clearly. R3 - BPA does not believe this needs to be spelled out as a stand alone requirement. R5 & R6 comment from GO/GOP- This requirement must contain the caveat supplied in R4 which excludes the requirement if the Transmission owner provides the fault measurement. R6 - a) BPA disagrees with R6.3 setting specific parameters of triggers, just specify what trigger coverage is needed and let the site determines its specific needs of the operating entity.b) BPA disagrees with need for 6.4, only need to require documenting what the triggers and settings are.R7 - a) BPA believes that the RE (with the RC and area entities) not only the RC should coordinate the area's needs for DDR. Appreciate that this requirement does not spell out a dry blanket approach that just makes needless work.b) BPA believes 7.2 should be part of 7.1 - as it is there is no way to enforce it, it's just a guideline. To have it at IROL or major EHV interconnection between coverage of DDR's is not needed everywhere only at significant stations.R9 - a) BPA disagrees with 9.3 specifying a value (20 mHz is too sensitive).b) Some places have existing DDR's that use analog transducers that output into the DDR. What sampling rate is the transducer? Or should this requirement apply to NEW DDR's? R10 - a) BPA believes that R 10.1 is not clear (means sufficient coverage that one line o/s doesn't stop the DDR functionality).b) Same for 10.2, what happens if there is no other voltage input during a sole bus outage? R13 - BPA believes that this can be an undue burden on some entities at the whim of the RC (not RE) determination. R14 - BPA believes this should be re-written to allow for major obstacles for a return to service - materials, substation catastrophe, etc. R15.2 - BPA disagrees with this as a requirement. Depending on how many entities request data, it may require extra workload to satisfy someone's curiosity. BPA also believes that Non-Disclosure agreements need to be in place. R16.3 - BPA believes there is a conflict with R1 - monitoring by older SCADA or DCS. R17.7 - BPA would like further clarification on “identified channels”.Thank you for the opportunity to comment.
Response: Many of the Commenter’s concerns do not pertain to Question 5, and were previously vetted through the Regional postings. Vetting technical issues was not the purpose of this NERC posting. However, the Drafting Team’s response to the comments is as follows: R1(a)--The 1 millisecond time resolution stipulated in requirement R16 for Sequence Of Event records is necessary for its use in event analysis, and is achievable.		

Organization	Yes or No	Question 5 Comment
		The 1 millisecond requirement specified is referring to the resolution of the data, not to the accuracy. NERC Standard PRC-018-1, R1.1 requires that clocks in DME devices be synchronized to within 2 milliseconds or less of UTC. NERC Standard PRC-002-2 (under development) identifies a requirement (R3) to apply a time stamp within 4 milliseconds of a change of state of the input device resolution in R3. R1(b)--1.1 is meant as written: "…where circuit breaker operation affects continuity of service to radial Loads…" If it takes more than one breaker to meet this requirement, then each of those breakers shall be monitored accordingly. R1(c)--1.2.2--monitoring to determine the time between tripping initiation and actual device tripping is essential for event analysis. It is also essential to know what protection operated to cause the trip. GO/GOP comment: The 2003 Blackout Investigation concluded that there was insufficient disturbance monitoring equipment installed to analyze the disturbance. This Standard ensures that there will be adequate resources in place for event analysis, and does not require adding new transmission or generation capacity. R2(a)--R3 was deliberately added to emphasize the importance to determine the Current Zero Time for BES transmission elements. R2 and R3 refer to Transmission Owners, R4 refers to Generator Owners. R2(b)--Clarification is not needed for 2.4. R3--R3 was deliberately added to emphasize the importance to determine the Current Zero Time for BES transmission elements. GO/GOP--The statement in R4 freeing the Generator Owner from having to install Fault recording capability applies to R5, and R6, and is implicit in the sequencing of the requirements. R6(a)--The trigger settings (6.3) were developed by the subject matter experts on the Drafting Team, and were public on the three postings of the standard. The Drafting Team has responded to any comments that were received. (Responses to the comments received from the three postings of the standard are available on the NPCC Website). R6(b)--The Drafting Team recognized the importance of the neutral overcurrent, and phase undervoltage triggers in 6.3.2, and 6.3.3. 6.4 was developed to ensure that all settings above and beyond those delineated in 6.3.2, and 6.3.3 were captured. R7(a)-- Requirements were directed at the Reliability Coordinators rather than the Regional Entities because of the international composition of NPCC's membership which requires a need for flexibility with those provincial RCs that have more intimate technical and operational knowledge of their systems than does the RE. R7(b)--The items contained in 7.1 and 7.2 are for the RCs consideration. A RC would just have to show that the items listed in 7.2 were considered. DDR disturbance information is only mandated from IROL elements, and at major EHV interconnections between operating areas. R9(a)-- The delta frequency 20mHz change trigger setting (9.3.3) was decided on by the subject matter experts on the Drafting Team, was necessary to acquire the level of information needed for event analysis, was selected based on system operations experience, and was technologically available to the industry. This trigger setting was made public on the three postings of the standard. The Drafting Team responded to comments received. (Responses to the comments received from the three postings of the standard are available on the NPCC Website). R9(b)--The "sample rate" of an analog transducer is continuous. If the recorder is recording the analog quantities continuously, it meets the minimum sample rate

Organization	Yes or No	Question 5 Comment
requirement. This requirement applies to all DDRs. Also, this Standard specifies requirements for the DDR devices, and not other devices such as transducers. R10(a)--10.1 was, as is written, to ensure that normal line maintenance activities do not interfere with DDR functionality. R10(b)--Even with the bus outage scenario described, the RC must ensure that a bus voltage would have to be provided to ensure DDR functionality. R13--This will not present an undue burden. The requirement stipulates mutual agreement on an implementation schedule. R14--Major obstacles for a return to service are addressed in 14.7. R15.2--The obligations of NPCC Full Members are listed in Article IX.A.2 of the NPCC Bylaws. A Full Member has an obligation "to plan and design its bulk power system and conduct its operations in compliance with ERO Reliability Standards, Regional Reliability Standards, and…" This requirement mandates that an entity share information (on request) that may be needed to fully investigate a disturbance. Without this requirement, issues can go unresolved indefinitely. This cooperation can be instrumental in resolving operational and planning coordination problems between Transmission Owners and Generator Owners, and between Transmission Owners. R16.3--The 1 millisecond time resolution stipulated in requirement R16.3 for Sequence Of Event records is necessary for its use in event analysis, and is available to industry. From the response to R1(a), Generators with DCSs that use SNTP or similar time protocol may not be able to achieve this without modification. However, the addition of a small events monitor with a GPS clock would be sufficient for most sites. Even though SCADA systems are not typically used for SOE applications, they can be retrofitted. The 1 millisecond resolution can also be accomplished through the use of digital relays. The typical resolution capabilities provided by SCADA systems are not adequate. NERC standard PRC-002-2 which is under development identifies a 4 millisecond resolution in R3. The 1 millisecond requirement specified is more stringent, and necessary for the acquisition of meaningful data for analysis. R17.7--The RC, TO, and GO must have the information available that identifies what each channel is used for.		
Northeast Utilities	Yes	
US Bureau of Reclamation	Yes	
Independent Electricity System Operator	Yes	
Pepco Holdings, Inc.	Yes	