Exhibit B

Comparison of PRC-002-NPCC-01 Regional Reliability Standard Requirements to Continent-Wide Reliability Standard PRC-002-2 Requirements

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
LOCATIONS FOR DATA CAPTURE (SER, FR) R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) 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 (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance	**LOCATIONS FOR DATA CAPTURE (SER, FR)** R1. Each Transmission Owner shall: 1.1. 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. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate 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 re-evaluated list of BES buses as per the Implementation Plan.	**LOCATIONS FOR DATA CAPTURE (SER, FR)** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data in PRC-002-2, PRC-002-2 does not require SER coverage at as many buses as PRC-002-NPCC-01. There is no FR or SER required by PRC-002-2 from generators. Locations requiring monitoring in PRC-002-NPCC-01 were amended by Compliance Guidance Statements CGS-002 Defining Generator Materiality for Registration dated May 4, 2009 (to be retired 7/1/16), CGS-004 Generating Plant Capacity in PRC-002-NPCC-01 dated March 20, 2013, and CGS-005 Clarification of Monitoring and Enforcement of PRC-002-NPCC-01.	Specifics provided in the sections below on SOE (PRC-002-NPCC-01), SER (PRC-002-2), Fault recording (FR), and DDR.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas.		activities do not interfere with DDR requirements. - Bus voltages		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
SOE R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) 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 (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive	**SER** R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	**SOE** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 3.3. Sequence of Events recording shall monitor the following at each location: - Transmission and Generator circuit breaker positions - **Protective Relay** tripping for all **protection groups** - **Teleprotection** keying & receive	PRC-002-NPCC-01 is more specific and inclusive in the locations (substations and generating units) where SOE is to be provided (PRC-002-NPCC-01 Parts 1.1 and 1.2). Also more specific in that it specifies that SER is to be provided for protective relay tripping and teleprotection keying.	3.2--for generating units, 50MW to be changed to 50MVA, 300MW to 300MVA. Add radial loads greater than 300MW, or the operation of which creates a Generation/Load island. Bulk power system to be changed to Bulk Electric System.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
FAULT RECORDING **R2.** Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R3.** Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. **R4.** Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. **R5.** Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: **5.1** Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) **5.2** Three phase currents and neutral currents. **5.3** Polarizing currents and voltages, if used. **5.4** Frequency. **5.5** Real and reactive power. **R6.** Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: **6.1** Each Fault recorder record duration shall be a minimum of one (1) second. **6.2** Each Fault recorder shall have a minimum recording rate of 16 samples per cycle	**FAULT RECORDING** R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: 3.1 Phase-to-neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: 4.1 A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total 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. 4.2 A minimum recording rate of 16 samples per cycle. 4.3 Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.	**FAULT RECORDING** 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22. 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt. 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) - Three phase currents and neutral currents. - Polarizing currents and voltages, if used. - Frequency. - Active and reactive power. 4.6 **Fault** recorder record duration shall be a minimum of one (1) second. 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle. 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data, PRC-002-2 doesn't require SER coverage at as many buses as PRC-002-NPCC-01. Current Zero Time is not addressed in PRC-002-2. There NO FR required by PRC-002-2 from generators. PRC-002-2 does not require recording polarizing currents or voltages, frequency, and real and reactive power. PRC-002-NPCC-01 specifies a record duration of one (1) second. PRC-002-2 specifies "at least 30-cycles" or "two cycles of the pre-trigger data…and the final cycle of the fault…" PRC-002-NPCC-01 specifies fault recorder triggering for specified per unit values of rated CT secondary current, set per unit values of neutral (residual) overcurrent, specified undervoltage per unit value, and documentation of additional triggers when necessary.	Triggering for monitored phase overcurrent set at 1.5 pu or less. 4.4--Change BPS to BES Remove "345kV and above" from shunt capacitors Add shunt reactors 4.1--Change BPS to BES 4.2-- Change BPS to BES 4.3--Change MW to MVA 4.5--Change Active to Real 4.8--Add monitored phase overcurrent set at 1.5 pu or less of rated CT secondary current Add "or greater" to "Phase undervoltage set at 0.85 pu"

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
6.3 Each Fault recorder shall be set to trigger for at least the following: **6.3.1** Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups. **6.3.2** Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current. **6.3.3** Monitored phase undervoltage set at 0.85 pu or greater. **6.4** Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.		- **Protective Relay** tripping for all **protection groups** - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current - Phase undervoltage set at 0.85 pu 4.9 When local conditions require different settings or additional functions, such situations shall be documented.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DYNAMIC DISTURBANCE RECORDING **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas. **R8.** Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. **R9.** Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: **9.1** A minimum recording time of sixty (60) seconds per trigger event. **9.2** A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second. **9.3** Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities): **9.3.1** Rate of change of Frequency. **9.3.2** Rate of change of Power. **9.3.3** Delta Frequency (recommend 20 mHz change). **9.3.4** Oscillation of Frequency. **R10.** Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: **10.1** Line currents for most lines such that	**DYNAMIC DISTURBANCE RECORDING** R5. Each Responsible Entity shall: 5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: 5.1.1 Generating resource(s) with: 5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA. 5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Re-evaluate all BES Elements at least once	**DYNAMIC DISTURBANCE RECORDING** 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements. - Bus voltages 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current. 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Voltage, current, and frequency - Active and reactive power 5.7 DDRs installed after January 1, 2009 shall function	For non-continuous recorders, PRC-002-2 specifies triggered record lengths of at least 3 minutes versus 60 seconds for PRC-002-NPCC-01 (R9). PRC-002-2 specifies an output recording rate of at least 30 times per second. PRC-002-NPCC-01 specifies a minimum data storage rate of 6 data points per second. PRC-002-2 specifies an off nominal frequency trigger (if used). PRC-002-2 is specific on the rate of change of frequency trigger values (if used). PRC-002-2 specifies an undervoltage trigger (if used). PRC-002-NPCC-01 specifies a rate of change of Power trigger (if used). PRC-002-NPCC-01 specifies a Delta Frequency trigger (if used), and an oscillation of Frequency trigger (if used). PRC-002-2 stipulates that normal line maintenance does not interfere with DDR functionality for monitoring line currents. PRC-002-2 stipulates that normal bus maintenance does not interfere with DDR functionality for monitoring bus voltages. PRC-002-NPCC-01 addresses DDR installation. PRC-002-2 does not address equipment.	5.1--Add "The Reliability Coordinator shall request DDR capability, and shall, with Transmission Owners, and Generator Owners mutually agree on an implementation schedule." 5.2--Change "control" to "operating". 5.3--Change BPS to BES Change "bulk power System" to Bulk Electric System 5.4--Revise first bullet to read "Lines and buses such that …" 5.4--"Bus voltages" should be "bus". 5.6--Change Active to real. Add 5.12: Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings and the required list of monitored quantities and report this to NPCC upon request.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
normal line maintenance activities do not interfere with DDR functionality. **10.2** Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. **10.3** As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current. **10.4** Frequency. **10.5** Real and reactive power. **R11.** Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. **R12.** Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. **R13.** Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: 7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level. 7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. 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. If the equipment was installed prior to the effective	as continuous recorders. 5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.) 5.9 The following DDR triggers shall be considered where available based on manufacturers capability: - Rate of change of Frequency - Rate of change of Power - Delta Frequency 20 mHz change - Oscillation of Frequency 5.10 When local conditions require different settings or additional functions, such situations shall be documented. 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
	date of this standard and is not capable of continuous recording, triggered records must meet the following: 8.1 Triggered record lengths of at least three minutes. 8.2 At least one of the following three triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75Hz >61.0Hz o Western Interconnection <59.55Hz >61.0Hz o ERCOT Interconnection <59.35Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55Hz >61.5Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds. R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.			

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
TIME SYNCHRONIZATION **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**TIME SYNCHRONIZATION** 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: 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.	**TIME SYNCHRONIZATION** **7.0 Time Synchronization** Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.	PRC-002-2, and PRC-018-1 (to be retired 6 years after the implementation date for PRC-002-2) specify synchronization of ± 2 milliseconds and its coordination to UTC.	Section 6--Add 7.1: Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA SPECIFICATIONS **R15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: **15.1** NERC, Regional Entity, Reliability Coordinator. **15.2** Request from other Transmission Owners, Generator Owners within NPCC. **R16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: **16.1** The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111. **16.2** Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232. **16.3** Fault Recorder and DDR Files shall contain all monitored channels. SER records shall contain station name, date, time resolved to milliseconds, SER point name, status.	**DATA SPECIFICATIONS** **R11.** Each Transmission Owner and Generator Owner shall provide, upon request, 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 the Responsible Entity, Regional Entity, or NERC in accordance with the following: **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	**DATA SPECIFICATIONS** 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases: - Request from NERC **Disturbance** Investigation Team - Request from NPCC **Disturbance** Investigation Team - Reliability Coordinator Request 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO. 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8). 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SER records shall contain station, date, time resolved to milliseconds, SER point name, status. 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar	PRC-002-2 stipulates 30 days unless an extension is granted. PRC-002-2 and PRC-018-1 stipulate that data is retrievable for 10 calendar days. PRC-002-2 is more specific on the data parameters. PRC-002-NPCC-01 is more specific as to the time resolution for SER data. PRC-018-1 stipulates archiving of data for at least three years. A-15 specifies archiving for 3 years. Note: PRC-018-1 is going to be retired in six years after the implementation period for PRC-002-2.	Section 6-- **NOTE: This is also in C-25 Procedure to Collect Power System Event Data for Analysis of System Performance**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
		days. R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4). R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
STATUS OF RECORDING CAPABILITY **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their Basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**STATUS OF RECORDING CAPABILITY** **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: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) Regional Entity and implement it.	**STATUS OF RECORDING CAPABILITY** **8.0 Maintenance And Testing** Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes: • Maintenance and testing intervals and their basis. • Summary of maintenance and testing procedures. **PRC-018-1 Requirement** R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.		With the exception of PRC-002-NPCC-01 Part 14.4 (time synchronization), Requirement R14 to be added. **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA ON THE DISTURBANCE MONITORING EQUIPMENT **R17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: **17.1** Type of DME. **17.2** Make and model of equipment. **17.3** Installation location. **17.4** Operational Status. **17.5** Date last tested. **17.6** Monitored Elements. **17.7** All identified channels. **17.8** Monitored electrical quantities.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** Not Applicable.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard: - Type of DME - Make and model of equipment - Installation location - Operational Status - Date last tested - Monitored **Elements** - Monitored Devices - Monitored Electrical Quantities **PRC-018-1 Requirement** R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8. Monitored electrical quantities, such as voltage, current, etc.	No gaps with PRC-018-1.	6.7--Revise "Monitored Devices" bullet to read "All identified channels"

Exhibit C

Complete Record of Retirement Development

Regional Reliability Standards Under Development

Regional Reliability Standards - Under Development				
Standard No.	**Title**	**Regional Status**	**Dates**	**NERC Status**
Northeast Power Coordinating Council (NPCC)				
PRC-002-NPCC-01	Disturbance Monitoring	Standard Under Development	01/06/16 - 02/19/16	Proposed Standard for Retirement **(1)** Ballot Results Announcement **(2)** Info **(3)** Submit Comments Unofficial Comment Form (Word) **(4)** Comments Received **(4i)**

A. Introduction

1. **Title:** **Disturbance Monitoring**
2. **Number:** PRC-002-NPCC-01
3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
   - **4.3.** Reliability Coordinator
5. **(Proposed) Effective Date:** To be established.

B. Requirements

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 (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area’s requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the

Owner failed to provide…				current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

	through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…	Not applicable.	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.

and the required list of monitored quantities as described in R10 for…				
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that

	14.7.			meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	November 4, 2010	Adopted by NERC Board of Trustees	New
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-01 (FERC's Order became effective on October 20, 2011)	

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

December 2nd, 2015

NPCC Full and General Members:

In accordance with the NPCC Regional Standard Processes Manual the ballot period for the retirement of NPCC Regional Standard PRC-002-NPCC-02 Disturbance Monitoring closed at 23:59PM on November 26th, 2015.

The results of the ballot were as follows:

Quorum: 69.69% of the Total Registered.
Approval: 97.10%

No negative ballots were received with comments therefore, in accordance with our Standards Processes Manual a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on February 2, 2016.

Contingent upon the approval of the NPCC BOD, the proposal to retire PRC-002-NPCC-02 will be submitted to the NERC Board of Trustees with subsequent filings with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full retirement record for the standard may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

Thank you for your participation.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
Main: 212-840-1070
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Regional Reliability Standards Announcement

Proposed Retirement of PRC-002-NPCC-01

Comment Period Open through February 19, 2016

Now Available

The Northeast Power Coordinating Council (NPCC) has requested NERC to post regional reliability standard **PRC-002-NPCC-01 – Disturbance Monitoring** for a 45-day industry review as permitted by the NERC Rules of Procedure. The comment period is open through **8 p.m. Eastern, Friday, February 19, 2016.**

Commenting

Use the electronic form to submit comments. If you experience any difficulties in using the electronic form, contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the Regional Reliability Standards Under Development Page.

Background

During 2014 and 2015, NERC completed, filed, and gained the FERC approval of the NERC PRC-002-2 Disturbance Monitoring (DM) continent-wide standard. In conformance with the ERO's strategic direction with respect to regional standards, NPCC conducted a review of the DM regional and continent-wide standards. It was determined that the NPCC regional standard was no longer necessary and initiated the process to retire it.

Regional Reliability Standards Development Process

Section 300 of NERC's Rules of Procedures of the Electric Reliability Organization governs the regional reliability standards development process.

For more information or assistance, contact Reliability Standards Analyst, Mat Bunch (via email) or at 404-446-9785.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Unofficial Comment Form

Recommended Retirement of Regional Reliability Standard PRC-002-NPCC-01

DO NOT use this form for submitting comments. Use the electronic form to submit comments on the proposed retirement of Regional Reliability Standard **PRC-002-NPCC-01 – Disturbance Monitoring**. The electronic form must be submitted by **8 p.m. Eastern, Friday, February 19, 2016.**

Documents and information about this project are available on the Regional Reliability Standards Under Development page. If you have questions, contact Mat Bunch (via email) or at 404-446-9785.

Background Information

During 2014 and 2015, NERC completed, filed, and gained the FERC approval of the NERC PRC-002-2 Disturbance Monitoring continent-wide standard. In conformance with the ERO's strategic direction with respect to regional standards, NPCC conducted a review of the DM regional and continent-wide standards. It was determined that the NPCC regional standard was no longer necessary and initiated the process to retire it.

The approval process for the retirement of a regional reliability standard requires NERC to publicly notice and request comment on the proposed standard. Comments shall be permitted only on the following criteria (technical aspects of the standard are vetted through the regional standards development process):

Open — Regional reliability standards shall provide that any person or entity that is directly and materially affected by the reliability of the bulk power system within the regional entity shall be able to participate in the development and approval of reliability standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the regional entity, a regional entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

Inclusive — Regional reliability standards shall provide that any person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process, if adversely affected.

Balanced — Regional reliability standards shall have a balance of interests and shall not be dominated by any two-interest categories and no single-interest category shall be able to defeat a matter.

Due Process — Regional reliability standards shall provide for reasonable notice and opportunity for public comment. At a minimum, the standard shall include public notice of the intent to develop a standard, a public comment period on the proposed standard, due consideration of those public comments, and a ballot of interested stakeholders.

Transparent — All actions material to the process of retiring regional reliability standards shall be transparent. All standards development meetings shall be open and publicly noticed on the regional entity's Web site.

Review the proposed retirement of PRC-002-NPCC-01 regional standard and answer the following questions:

1. Do you agree the process of retiring PRC-002-NPCC-01 met the "Open" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

2. Do you agree the process of retiring PRC-002-NPCC-01 met the "Inclusive" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

3. Do you agree the process of retiring PRC-002-NPCC-01 met the "Balanced" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

4. Do you agree the process of retiring PRC-002-NPCC-01 met the "Due Process" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

5. Do you agree the process of retiring PRC-002-NPCC-01 met the "Transparent" criteria as outlined above? If "No", please explain in the comment area below.

☐ Yes
☐ No
Comments:

Individual or group. (5 Responses)
Name (5 Responses)
Organization (4 Responses)
Question 1 (5 Responses)
Question 1 Comments (0 Responses)
Question 2 (5 Responses)
Question 2 Comments (0 Responses)
Question 3 (5 Responses)
Question 3 Comments (0 Responses)
Question 4 (5 Responses)
Question 4 Comments (0 Responses)
Question 5 (5 Responses)
Question 5 Comments (0 Responses)

Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Yes
Yes
Yes
Individual
Si Truc Phan
Hydro-Quebec TransEnergie
Yes
Yes
Yes
Yes
Yes
Individual
Michael Puscas

ISO-NE
Yes
Yes
Yes
Yes
Yes
Individual
Leonard Kula
Independent Electricity System Operator
Yes
Yes
Yes
Yes
Yes
Individual
Randi Heise
Dominion Resources, Inc.
Yes
Yes
Yes
Yes
Yes

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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March 25, 2015

Subject: Solicitation for NPCC Regional Standard Drafting Team Members for "Disturbance Monitoring" PRC-002-NPCC-02

Dear Sir/Madam,

A new RSAR for NPCC Regional Standard PRC-002-NPCC-02 Disturbance Monitoring has been approved by the RSC, and assigned to TFSP by the RCC. In accordance with the NPCC Regional Standard Processes Manual , NPCC is soliciting for any interested candidates to assist with the drafting of the standard. The anticipated workload is 2-3 "in-person" meetings and 4-6 teleconferences. Attached is a self-nomination form to be completed and returned by any interested persons no later than April 10th, 2015. The Regional Standards Committee will review and approve any additional qualified candidates who self nominate at its April 22-23, 2015 meeting. Please distribute this email to any potential interested candidates. This information will also be posted on the NPCC website.

Sincerely,

Lee Pedowicz
Manager of Reliability Standards
NPCC Inc.
1040 Avenue of the Americas, 10th Floor
New York, NY 10018
(212) 840-1070
(212) 302-2782 FAX
lpedowicz@npcc.org

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Nomination Form for "PRC-002-NPCC-02", Disturbance Monitoring, Standard Drafting Team

Please return this form to NPCCstandard@npcc.org by **April 10, 2015** with the name of the RSAR or Standard Drafting Team in the subject line. If you have any questions, please contact Lee Pedowicz at lpedowicz@npcc.org , or by telephone at 212-840-1040.
All candidates' qualifications will be reviewed and participation on a drafting team is subject to the approval by the NPCC Regional Standards Committee, RSC. Applicants are expected to be prepared to participate actively at the Drafting Team meetings.

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the PRC-002-NPCC-02 Drafting Team.

I represent the following NERC Reliability Region(s) (check all that apply):	I represent the following NPCC Bylaw Defined Industry Sectors (check one):	
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — Reliability Coordinators
	☐	3 — TDUs, Distribution Companies and Load-Serving Entities
	☐	4 — Generator Owners
	☐	5 — Marketers, Brokers and Aggregators
	☐	6 — State and Provincial Regulatory and/or Governmental Authorities
	☐	7 — Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Coordinator	☐ Purchasing-Selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator (Resource Integrator)	☐ Reliability Coordinator
☐ Reliability Assurer	☐ Standards Developer

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

Non-Standard

Regional Standard:
PRC-002-NPCC-01

Disturbance Monitoring
Current Status:
Regional BOD Approved

View Supporting Documents

Approval & Implementation

Date	Action	
04/28/16	Approval Supporting Document posted publicly **(10)**	View Document
04/28/16	Approval Supporting Document posted publicly **(9)**	View Document
03/23/16	Region BOD Approval	

Ballot Period 11/16/2015 through 11/26/2015

Date	Action	
11/26/15	Ballot Period Ended	View Ballot Results
11/16/15	Ballot Period Started	View Ballot Submissions
11/16/15	Membership Ballot Document posted publicly **(8)**	View Document

Project Initiation / Drafting Team Formation

Date	Action	
02/23/15	RSAR Document posted publicly **(7)**	View Document
02/18/15	RSC Accepts	

Information in a Regional Standard Authorization Request (RSAR)

The tables below identify information to be submitted in a Regional Standard Authorization Request to the NPCC Regional Standards Process Manager, NPCCstandard@npcc.org . The NPCC Regional Standards Process Manager shall be responsible for implementing and maintaining this form as needed to support the information requirements of the standards process.

Regional Standard Authorization Request Form

Title of Proposed Standard:	PRC-002-NPCC-02
Request Date:	02-18-2015

RSAR Requester Information

Name:	Paul DiFilippo	**RSAR Type (Check box for one of these selections.)**	
Company:	NPCC	☐	New Standard
Telephone:	416-345-5042	☒	Revision to Existing Standard
Fax:		☐	Withdrawal of Existing Standard
Email:	paul.difilippo@HydroOne.com	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.**)**

The purpose of the proposed RSAR is to review the regional standard for potential revisions made necessary by the industry's adoption of the new NERC BES definition, the Paragraph 81 directive, and the development of NERC's PRC-002-2 Disturbance Monitoring and Reporting Requirements standard. Retiring PRC-002-NPCC-01 is to be considered if it is determined that it can be retired without sacrificing the ability to capture post-disturbance data.

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation**.)**

To enhance efficiencies and cost effectiveness, it must be determined if PRC-002-NPCC-01requirements should be revised or retired to address the new NERC BES definition, to incorporate Paragraph 81, and to eliminate redundancy leading to double jeopardy with PRC-002-2 requirements without sacrificing the ability to capture post-disturbance data.

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.**)**

The requirements in PRC-002-NPCC-01 will be reviewed individually for revision or deletion with respect to the new NERC BES definition and Paragraph 81. In addition, PRC-002-NPCC-01 will be reviewed against NERC's PRC-002-2. PRC-002-2 mandates the capturing of adequate data to facilitate the analysis of BES disturbances. This "umbrella" encompasses the relevant requirements in PRC-002-NPCC-01. However, the relevant requirements in each of the standards are to be compared and the requirements of PRC-002-NPCC-01, if so determined, will be revised or deleted to eliminate redundancy and the concomitant double jeopardy. The review will be governed by bullet 1 of the NERC Rules of Procedure, Section 312, Regional Reliability Standards, which reads "Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard."

After this review is completed, it will be determined if PRC-002-NPCC-01 should be revised, or retired.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☒	Reliability Coordinator	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
☐	Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
☐	Transmission Service Provider	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
☒	Transmission Owner	The entity that owns and maintains transmission facilities.
☐	Transmission Operator	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
☐	Transmission Planner	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area.
☐	Resource Planner	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

☐	Generator Operator	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☒	Generator Owner	Entity that owns and maintains generating units.
☐	Purchasing-Selling Entity	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
☐	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer.
☐	Load-Serving Entity	Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check all boxes that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an Common Attribute of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes

2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)
Review PRC-002-NPCC-01against PRC-002-2 to determine if revisions are necessary or retirement of PRC-002-NPCC-01 is possible.

Related Standards

Standard No.	**Explanation**
PRC-002-2	NERC Disturbance Monitoring and Reporting Requirements standard

Related SARs or RSARs

SAR ID	**Explanation**
RSAR-- 11/26/12	RSAR for PRC-002-NPCC-01 to be reviewed with respect to the revised BES definition (withdrawn).

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS. NEW YORK. NY 10018 (212) 840-1070 FAX (212) 302-2782

November 16, 2015

Subject: Notification of (10) Day Ballot Period for Retirement of Regional Standard PRC-002-NPCC-01 Disturbance Monitoring

Dear Madam/Sir:

On October 8, 2015, in accordance with the NPCC Regional Standards Process Manual (RSPM), the NPCC Regional Standards Committee (RSC) acting on the recommendation of the PRC-002-NPCC-01 Drafting Team, initiated the process to retire NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring.

The PRC -002-NPCC-01 standard drafting team was convened to address an RSC approved Regional Standard Authorization Request (RSAR) which proposed retiring PRC -002-NPCC-01 subsequent to FERC approval of PRC -002-2 *Disturbance Monitoring and Reporting Requirements*. PRC-002-2 was approved by the FERC on September 25, 2015 without any directives issued.

In accordance with the RSPM the retirement of PRC -002-NPCC-01 must be initially approved by the NPCC Full and General Members, with subsequent approvals by the NPCC Board of Directors, NERC Board of Trustees and finally filing with the applicable governmental authorities.

The PRC-002-NPCC-01 standard and all supporting documentation have been posted on the NPCC Website for a ten (10) day ballot period beginning November 16th, 2016.
https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

Please contact me with any questions.

Thank you.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
Main: 212-840-1070
Direct: 917-934-7976
Fax: 212-302-2782
Email: rshu@npcc.org

A. Introduction

1. **Title:** **Disturbance Monitoring**
2. **Number:** PRC-002-NPCC-01
3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.
4. **Applicability:**
   4.1. Transmission Owner
   4.2. Generator Owner
   4.3. Reliability Coordinator
5. **(Proposed) Effective Date:** To be established.

B. Requirements

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 (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the

Owner failed to provide…				current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.

	through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	
R7 The Reliability Coordinator failed to establish its area's requirements for…	Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.	More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…	Not applicable.	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.

and the required list of monitored quantities as described in R10 for…				
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed…	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that

	14.7.			meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	November 4, 2010	Adopted by NERC Board of Trustees	New
1	October 20, 2011	FERC Order issued approving PRC-002-NPCC-01 (FERC's Order became effective on October 20, 2011)	

NPCC, Inc.

NPCC Disturbance Monitoring Drafting Team WebEx/Call
Draft Minutes

August 13, 2015 01:00 p.m. - 03:00 p.m.

Call in 1-415-655-0003
Access Code 642 003 478
WebEx Password dmsdt

1. **Welcome-Introductions**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   Participants--Drafting Team Members
   Robert Pellegrini
   Tim Kucey
   Robert Grabovickic
   Jim Watson
   Brian Evans-Mongeon
   Lee Pedowicz
   RuiDa Shu
   Don Burkart
   Daniel Kidney
   George Wegh

   Observers
   Dave Bertagnolli
   Kelly Dash
   Po Bun Ear
   Juan Villar
   Brian Robinson

2. **<u>NPCC Antitrust Compliance Guidelines</u>**
   Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. **<u>Review Standard/Criteria Comparison Table</u>**
   Bob Pellegrini went over the objectives of the RSAR. Consideration was to be given to retiring PRC-002-NPCC-01 because of the NERC approval of PRC-002-2 (now pending with FERC). It was mentioned that Criteria A-15 was stay in place. George Wegh commented that A-15 will continue to exist because some Canadian entities did not accept PRC-002-NPCC-01. Bob Pellegrini added that A-15 might need refreshing.

   PRC-002-NPCC-01 Requirement R1 was discussed.

   Juan Villar commented that if it is decided to retire PRC-002-NPCC-01, then there must be an explanation in the petition to FERC as to why it is not needed.

   Meeting participants said that the BES is more encompassing than NPCC's Criteria A-10 BPS.

   Several participants shared the results of their internal assessments of SOE/DFR coverage differences between PRC-002-NPCC-01 and PRC-002-2. In each case the PRC-002-NPCC-01 standard was inclusive of the PRC-002-2 requirements, and in the majority of cases PRC-002-NPCC-01 required DME at 2 to 3 times the number of locations that PRC-002-2 required. The adequacy of data capture for event analysis obtainable from PRC-002-2, PRC-002-NPCC-01, and A-15 was discussed.

   The intention of PRC-002-NPCC-01 was to have it applicable to BPS Elements. At the time of its writing, the formal NERC BES definition that is in force today did not exist. BES versus BPS will be an issue.

   Bob Pellegrini felt that reliability would be diminished by not having a regional standard.

   Lee Pedowicz will find out how enforceable is NPCC Criteria.

   The question was raised as to whether or not PRC-002-2 and A-1 would be adequate to obtain disturbance monitoring data.

   The question of whether refreshing A-15 would aid in the retirement of PRC-002-NPCC-01 was discussed. It was suggested to revise A-15 to fill in any reliability gaps presented by the retirement of PRC-002-NPCC-01 with PRC-002-2 being in place.

   George Wegh said that TFSP will be looking to the Drafting Team to develop recommendations for revisions necessary in A-15. TFSP will be responsible for revising the A-15 Criteria document and possibly including it as part of a new directory.

How enforceable is A-15? It was felt that it applied to a smaller number of entities.

The Drafting Team will make changes to the provided table to align the necessary comparisons.

4. <u>Next Steps</u>

Another WebEx is planned for August 28, 2015 9:00 a.m. - 11:00 a.m. At that WebEx information on the enforceability of NPCC Criteria will be presented. Attendees should have hard copies of A-15, PRC-002-2, PRC-002-NPCC-01, and the Table to refer to, to facilitate comparisons.

5. <u>Future Meetings</u>

a. WebEx
Planned for Friday, August 28, 2015 from 9:00 a.m. - 11:00 a.m.

b. In person
Face-to-face meetings to be scheduled as needed.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

NPCC Disturbance Monitoring Drafting Team WebEx/Call
Draft Minutes

August 28, 2015 09:00 a.m. - 11:00 a.m.

Call in 1-415-655-0003
Access Code 642 003 478
***WebEx Password* Disturbance**

1. **Welcome-Introductions**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   Participants--Drafting Team Members
   Robert Pellegrini
   Tim Kucey
   Robert Grabovickic
   Jim Watson
   Lee Pedowicz
   RuiDa Shu
   Daniel Kidney
   George Wegh
   Paul Difilippo

   Observers
   Dave Bertagnolli
   Kelly Dash
   Juan Villar
   Scott Nied--NPCC Compliance
   Brian Robinson

2. **NPCC Antitrust Compliance Guidelines**
   Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. NPCC's Scott Nied--Compliance to call in to respond to enforceability questions

Scott Nied, NPCC compliance called in. Bob Pellegrini asked Scott about the compliance and enforceability implications of retiring PRC-002-NPCC-01, making a new directory for Disturbance Monitoring, and revising A-15. Scott Nied replied that because PRC-002-NPCC-01 is FERC approved, Compliance only enforces PRC-002-NPCC-01 if an entity has a NERC Compliance Registry (NCR) numbers. Full Members have to comply with Criteria and Directories. This compliance is a voluntary obligation, and is validated by a signed document. Brian Robinson asked what are the ramifications if you don't comply? Scott Nied answered that for Full Members this is self-policing.

Bob Pellegrini asked the Drafting Team if it would be in favor of retiring PRC-002-NPCC-01, do a gap analysis and give to TFSP to revise A-15, or develop a directory. Dave Bertagnolli agreed with that course of action.

Brian Robinson asked that if it came down to a variance of the as of yet not FERC approved PRC-002-2, could it be handled with NPCC's Regional Standard Processes Manual procedure as is being done with PRC-006? Lee Pedowicz was going to find out.

A discussion of retiring PRC-002-NPCC-01 began centering on how to justify the retirement of PRC-002-NPCC-01. Justification is that A-15 and a possible new directory would be more stringent.

4. Review Standard/Criteria Comparison Table

The comparison table was gone over. Paul Difilippo commented that there would be less disturbance monitoring coverage on BPS buses and generators without PRC-002-NPCC-01. A-15 would close any gaps.

George Wegh commented that the Drafting Team would have to make a recommendation on what would have to be revised in A-15.

Juan Villar commented that he liked the approach of retiring PRC-002-NPCC-01. He agreed that any gaps between PRC-002-2 and PRC-002-NPCC-01 could be addressed in A-15.

Any redundancies between A-15 and PRC-002-2 would have to be eliminated. It was suggested that the DDR section in A-15 could be removed~~.~~ since PRC-002-2 is far more inclusive than A-15.

4. Next Steps

The next WebEx is planned for September 11, 2015 1:00 p.m. - 3:00 p.m.

5. Future Meetings

a. WebEx

Planned for Friday, September 11, 2015 August 28, 2015 from 1:00 p.m. - 3:00 p.m.

b. In person

Face-to-face meetings to be scheduled as needed.

Northeast Power Coordinating Council, Inc. (NPCC)

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- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

LRP
4/27/2016~~9/1/2015~~

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

NPCC, Inc.

NPCC Disturbance Monitoring Drafting Team WebEx/Call
Minutes

September 11, 2015 01:00 p.m. - 03:00 p.m.

Call in 1-415-655-0003
Access Code 642 003 478
***WebEx Password* Disturbance**

<u>Summary</u>--it was decided by the meeting to retire PRC-002-NPCC-01, and have a new directory developed. FERC will be considering PRC-002-2 at its upcoming September 17, 2015 meeting.

1. **<u>Welcome-Introductions</u>**
   Lee Pedowicz made opening remarks and introduced the participants on the call.

   <u>Participants--Drafting Team Members</u>
   Robert Pellegrini
   Lee Pedowicz
   RuiDa Shu
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   Kelly Dash
   Juan Villar
   Brian Robinson

2. **<u>NPCC Antitrust Compliance Guidelines</u>**
   Lee Pedowicz read the NPCC Antitrust Compliance Guidelines.

3. **Review Standard/Criteria Comparison Table**

a. Revise A-15, or develop a directory

Lee Pedowicz gave a summary of how PRC-002-NPCC-01 can be handled--replace with a directory (and what would comprise a directory in terms of including B and C documents), revise Criteria A-15, or revise PRC-002-NPCC-01.

Robert Pellegrini asked for opinions on retiring PRC-002-NPCC-01 and developing a directory.

Lee Pedowicz discussed the directory development process, and referred the meeting to NPCC's Directory Development and Revision Manual.

Lee Pedowicz will handle all the administrative details going forward.

George Wegh led a discussion on a Directory addressing NPCC's BPS versus the continent-wide standard covering the BES. A discussion ensued over the possibility of overlapping requirements (there should not be redundancy between requirements) between PRC-002-2 and a new NPCC directory. The directory would have the more stringent requirements. From page 4 of NPCC's Directory Development and Revision Manual directed that "…an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards." Redundancy is to be avoided to ensure that there cannot be multiple violations because of the violation of one requirement.

Lee Pedowicz is going to get information on an overlap between Directory #1 and the relevant continent-wide standards.

Robert Pellegrini stated that because PRC-002-2 is more stringent for DDR, NPCC will follow PRC-002-2. This was agreed with by the meeting.

Lee Pedowicz mentioned that FERC will be discussing PRC-002-2 at its upcoming September 17, 2015 meeting. He will send electronically distribute FERC's announcement of the meeting, and send the Drafting Team its decision on PRC-002-2.

The question was raised regarding how compliance with PRC-002-NPCC-01 would be enforced by NPCC while the standard was being considered for retirement by FERC. Brian Robinson said that the precedent has been set for having standards not actively monitored by NPCC Compliance. Lee Pedowicz will check with NPCC Compliance to see how they would approach enforcing PRC-002-NPCC-01while it was with FERC for retirement consideration, but before it was officially retired, and see if it could be taken off the actively monitored list.

The development of a new directory would be given by NPCC to an outside contractor. That draft would be used as the foundation for its formal development.

Lee Pedowicz asked what the Drafting Team's role will be during this process, and George Wegh mentioned that review of the directory's development would be taken over by TFSP.

Lee Pedowicz to call in to the TFSP meeting September 16, 2015 to give an update on Disturbance Monitoring. (Note: George Wegh addressed PRC-002-NPCC-01 and Lee Pedowicz did not have to call in.)

4. <u>Next Steps</u>
Lee Pedowicz will handle the administration of the retirement of PRC-002-NPCC-01, and the development of a directory.

5. <u>Future Meetings</u>
a. WebEx--will be held if necessary.
b. In person

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

- Industry-related topics considered sensitive or market intelligence in nature that are outside of their committee's scope or assignment, or the published agenda for the meeting;
- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

Any decisions or actions by NPCC as a result of such meetings will only be taken in the interest of promoting and maintaining the reliability and adequacy of the bulk power system.

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
LOCATIONS FOR DATA CAPTURE (SER, FR) R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) 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 (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance	**LOCATIONS FOR DATA CAPTURE (SER, FR)** R1. Each Transmission Owner shall: 1.1. 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. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate 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 re-evaluated list of BES buses as per the Implementation Plan.	**LOCATIONS FOR DATA CAPTURE (SER, FR)** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data in PRC-002-2, PRC-002-2 does not require SER coverage at as many buses as PRC-002-NPCC-01. There is no FR or SER required by PRC-002-2 from generators. Locations requiring monitoring in PRC-002-NPCC-01 were amended by Compliance Guidance Statements CGS-002 Defining Generator Materiality for Registration dated May 4, 2009 (to be retired 7/1/16), CGS-004 Generating Plant Capacity in PRC-002-NPCC-01 dated March 20, 2013, and CGS-005 Clarification of Monitoring and Enforcement of PRC-002-NPCC-01.	Specifics provided in the sections below on SOE (PRC-002-NPCC-01), SER (PRC-002-2), Fault recording (FR), and DDR.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas.		activities do not interfere with DDR requirements. - Bus voltages		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
SOE R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SER) 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 (DCS) or part of Fault recording equipment. This capability shall: 1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity. 1.2 Monitor the following at each location listed in 1.1: 1.2.1 Transmission and Generator circuit breaker positions 1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1. 1.2.3 Teleprotection keying and receive	**SER** R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses.	**SOE** 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity** 3.3. Sequence of Events recording shall monitor the following at each location: - Transmission and Generator circuit breaker positions - **Protective Relay** tripping for all **protection groups** - **Teleprotection** keying & receive	PRC-002-NPCC-01 is more specific and inclusive in the locations (substations and generating units) where SOE is to be provided (PRC-002-NPCC-01 Parts 1.1 and 1.2). Also more specific in that it specifies that SER is to be provided for protective relay tripping and teleprotection keying.	3.2--for generating units, 50MW to be changed to 50MVA, 300MW to 300MVA. Add radial loads greater than 300MW, or the operation of which creates a Generation/Load island. Bulk power system to be changed to Bulk Electric System.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
FAULT RECORDING **R2.** Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: **2.1** All transmission lines. **2.2** Autotransformers or phase-shifters connected to busses. **2.3** Shunt capacitors, shunt reactors. **2.4** Individual generator line interconnections. **2.5** Dynamic VAR Devices. **2.6** HVDC terminals. **R3.** Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. **R4.** Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. **R5.** Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: **5.1** Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) **5.2** Three phase currents and neutral currents. **5.3** Polarizing currents and voltages, if used. **5.4** Frequency. **5.5** Real and reactive power. **R6.** Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: **6.1** Each Fault recorder record duration shall be a minimum of one (1) second. **6.2** Each Fault recorder shall have a minimum recording rate of 16 samples per cycle	**FAULT RECORDING** R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: 3.1 Phase-to-neutral voltage for each phase of each specified BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1 Transformers that have a low-side operating voltage of 100kV or above. 3.2.2 Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: 4.1 A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total 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. 4.2 A minimum recording rate of 16 samples per cycle. 4.3 Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.	**FAULT RECORDING** 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22. 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt. 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**. 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed: - All **BPS** Transmission Lines - Autotransformers or phase-shifters connected to **BPS** busses - Shunt capacitors 345 kV and above - Individual generator interconnections - Dynamic Var Devices - HVDC Terminals - A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus. 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.) - Three phase currents and neutral currents. - Polarizing currents and voltages, if used. - Frequency. - Active and reactive power. 4.6 **Fault** recorder record duration shall be a minimum of one (1) second. 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle. 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:	Because of its Attachment 1 Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data, PRC-002-2 doesn't require SER coverage at as many buses as PRC-002-NPCC-01. Current Zero Time is not addressed in PRC-002-2. There NO FR required by PRC-002-2 from generators. PRC-002-2 does not require recording polarizing currents or voltages, frequency, and real and reactive power. PRC-002-NPCC-01 specifies a record duration of one (1) second. PRC-002-2 specifies "at least 30-cycles" or "two cycles of the pre-trigger data…and the final cycle of the fault…" PRC-002-NPCC-01 specifies fault recorder triggering for specified per unit values of rated CT secondary current, set per unit values of neutral (residual) overcurrent, specified undervoltage per unit value, and documentation of additional triggers when necessary.	Triggering for monitored phase overcurrent set at 1.5 pu or less. 4.4--Change BPS to BES Remove "345kV and above" from shunt capacitors Add shunt reactors 4.1--Change BPS to BES 4.2-- Change BPS to BES 4.3--Change MW to MVA 4.5--Change Active to Real 4.8--Add monitored phase overcurrent set at 1.5 pu or less of rated CT secondary current Add "or greater" to "Phase undervoltage set at 0.85 pu"

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
6.3 Each Fault recorder shall be set to trigger for at least the following: **6.3.1** Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups. **6.3.2** Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current. **6.3.3** Monitored phase undervoltage set at 0.85 pu or greater. **6.4** Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.		- **Protective Relay** tripping for all **protection groups** - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current - Phase undervoltage set at 0.85 pu 4.9 When local conditions require different settings or additional functions, such situations shall be documented.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DYNAMIC DISTURBANCE RECORDING **R7.** Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: **7.1** Provides a minimum of 1 DDR per 3,000 MW of peak Load. **7.2** Records dynamic disturbance information with consideration of the following facilities/locations: **7.2.1** Major Load centers. **7.2.2** Major Generation clusters. **7.2.3** Major voltage sensitive areas. **7.2.4** Major transmission interfaces. **7.2.5** Major transmission junctions. **7.2.6** Elements associated with Interconnection Reliability Operating Limits (IROLs). **7.2.7** Major EHV interconnections between operating areas. **R8.** Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. **R9.** Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: **9.1** A minimum recording time of sixty (60) seconds per trigger event. **9.2** A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second. **9.3** Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities): **9.3.1** Rate of change of Frequency. **9.3.2** Rate of change of Power. **9.3.3** Delta Frequency (recommend 20 mHz change). **9.3.4** Oscillation of Frequency. **R10.** Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: **10.1** Line currents for most lines such that	**DYNAMIC DISTURBANCE RECORDING** R5. Each Responsible Entity shall: 5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: 5.1.1 Generating resource(s) with: 5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA. 5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Re-evaluate all BES Elements at least once	**DYNAMIC DISTURBANCE RECORDING** 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices. 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors: - Major **load** centers - Major **generation** clusters - Major voltage sensitive areas - Major transmission interfaces - Major transmission junctions - **Elements** associated with Interconnection Reliability Operating Limits (IROLs) - Major EHV interconnections between control areas. 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.) 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed: - Most lines such that normal maintenance activities do not interfere with DDR requirements. - Bus voltages 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current. 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following: - Voltage, current, and frequency - Active and reactive power 5.7 DDRs installed after January 1, 2009 shall function	For non-continuous recorders, PRC-002-2 specifies triggered record lengths of at least 3 minutes versus 60 seconds for PRC-002-NPCC-01 (R9). PRC-002-2 specifies an output recording rate of at least 30 times per second. PRC-002-NPCC-01 specifies a minimum data storage rate of 6 data points per second. PRC-002-2 specifies an off nominal frequency trigger (if used). PRC-002-2 is specific on the rate of change of frequency trigger values (if used). PRC-002-2 specifies an undervoltage trigger (if used). PRC-002-NPCC-01 specifies a rate of change of Power trigger (if used). PRC-002-NPCC-01 specifies a Delta Frequency trigger (if used), and an oscillation of Frequency trigger (if used). PRC-002-2 stipulates that normal line maintenance does not interfere with DDR functionality for monitoring line currents. PRC-002-2 stipulates that normal bus maintenance does not interfere with DDR functionality for monitoring bus voltages. PRC-002-NPCC-01 addresses DDR installation. PRC-002-2 does not address equipment.	5.1--Add "The Reliability Coordinator shall request DDR capability, and shall, with Transmission Owners, and Generator Owners mutually agree on an implementation schedule." 5.2--Change "control" to "operating". 5.3--Change BPS to BES Change "bulk power System" to Bulk Electric System 5.4--Revise first bullet to read "Lines and buses such that …" 5.4--"Bus voltages" should be "bus". 5.6--Change Active to real. Add 5.12: Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings and the required list of monitored quantities and report this to NPCC upon request.

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
normal line maintenance activities do not interfere with DDR functionality. **10.2** Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. **10.3** As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current. **10.4** Frequency. **10.5** Real and reactive power. **R11.** Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. **R12.** Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. **R13.** Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.	every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: 7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level. 7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. 7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. 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. If the equipment was installed prior to the effective	as continuous recorders. 5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.) 5.9 The following DDR triggers shall be considered where available based on manufacturers capability: - Rate of change of Frequency - Rate of change of Power - Delta Frequency 20 mHz change - Oscillation of Frequency 5.10 When local conditions require different settings or additional functions, such situations shall be documented. 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
	date of this standard and is not capable of continuous recording, triggered records must meet the following: 8.1 Triggered record lengths of at least three minutes. 8.2 At least one of the following three triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75Hz >61.0Hz o Western Interconnection <59.55Hz >61.0Hz o ERCOT Interconnection <59.35Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55Hz >61.5Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds. R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.			

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
TIME SYNCHRONIZATION **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**TIME SYNCHRONIZATION** 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: 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.	**TIME SYNCHRONIZATION** **7.0 Time Synchronization** Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.	PRC-002-2, and PRC-018-1 (to be retired 6 years after the implementation date for PRC-002-2) specify synchronization of ± 2 milliseconds and its coordination to UTC.	Section 6--Add 7.1: Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA SPECIFICATIONS **R15.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: **15.1** NERC, Regional Entity, Reliability Coordinator. **15.2** Request from other Transmission Owners, Generator Owners within NPCC. **R16.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: **16.1** The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111. **16.2** Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232. **16.3** Fault Recorder and DDR Files shall contain all monitored channels. SER records shall contain station name, date, time resolved to milliseconds, SER point name, status.	**DATA SPECIFICATIONS** **R11.** Each Transmission Owner and Generator Owner shall provide, upon request, 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 the Responsible Entity, Regional Entity, or NERC in accordance with the following: **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.	**DATA SPECIFICATIONS** 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases: - Request from NERC **Disturbance** Investigation Team - Request from NPCC **Disturbance** Investigation Team - Reliability Coordinator Request 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO. 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8). 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SER records shall contain station, date, time resolved to milliseconds, SER point name, status. 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME. **PRC-018-1 Requirement** R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar	PRC-002-2 stipulates 30 days unless an extension is granted. PRC-002-2 and PRC-018-1 stipulate that data is retrievable for 10 calendar days. PRC-002-2 is more specific on the data parameters. PRC-002-NPCC-01 is more specific as to the time resolution for SER data. PRC-018-1 stipulates archiving of data for at least three years. A-15 specifies archiving for 3 years. Note: PRC-018-1 is going to be retired in six years after the implementation period for PRC-002-2.	Section 6-- **NOTE: This is also in C-25 Procedure to Collect Power System Event Data for Analysis of System Performance**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
		days. R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4). R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.		

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
STATUS OF RECORDING CAPABILITY **R14.** Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: **14.1** Maintenance and testing intervals and their Basis. **14.2** Summary of maintenance and testing procedures. **14.3** Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)). **14.4** Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center). **14.5** Monthly verification of active analog quantities. **14.6** Verification of DDR and DFR settings in the software every six (6) years. **14.7** A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.	**STATUS OF RECORDING CAPABILITY** **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: • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) Regional Entity and implement it.	**STATUS OF RECORDING CAPABILITY** **8.0 Maintenance And Testing** Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes: • Maintenance and testing intervals and their basis. • Summary of maintenance and testing procedures. **PRC-018-1 Requirement** R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.		With the exception of PRC-002-NPCC-01 Part 14.4 (time synchronization), Requirement R14 to be added. **NOTE: This is also in B-26 Guide for Application of Disturbance Recording Equipment**

PRC-002-NPCC-01 REQUIREMENTS	PRC-002-2 REQUIREMENTS	A-15	Differences Between PRC-002-NPCC-01 and PRC-002-2	A-15 Revisions Needed
DATA ON THE DISTURBANCE MONITORING EQUIPMENT **R17.** Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: **17.1** Type of DME. **17.2** Make and model of equipment. **17.3** Installation location. **17.4** Operational Status. **17.5** Date last tested. **17.6** Monitored Elements. **17.7** All identified channels. **17.8** Monitored electrical quantities.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** Not Applicable.	**DATA ON THE DISTURBANCE MONITORING EQUIPMENT** 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard: - Type of DME - Make and model of equipment - Installation location - Operational Status - Date last tested - Monitored **Elements** - Monitored Devices - Monitored Electrical Quantities **PRC-018-1 Requirement** R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8. Monitored electrical quantities, such as voltage, current, etc.	No gaps with PRC-018-1.	6.7--Revise "Monitored Devices" bullet to read "All identified channels"

NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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October 16, 2015

Subject: Notification of Pre-Ballot Review for Retirement of Regional Standard PRC-002-NPCC-01 Disturbance Monitoring

Dear Madam/Sir:

On October 8, 2015 NPCC's Regional Standards Committee acting on the recommendation of the PRC-002-NPCC-02 Drafting Team, authorized the use of NPCC's standards process for retirement of NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring. The Drafting Team had been convened to address an approved Regional Standard Authorization Request (RSAR), and it decided that PRC-002-NPCC-01 could be retired dependent upon the FERC approval of continent-wide PRC-002-2 Disturbance Monitoring and Reporting Requirements. PRC-00-2 was approved by the FERC September 25, 2015 without any directives issued.

In accordance with the NPCC Regional Standard Processes Manual (RSPM), this authorization for retirement is to first be approved by the NPCC Members with subsequent approvals by the NPCC Board of Directors, NERC Board of Trustees, and then filing for approval of the retirement with the applicable governmental authorities. PRC-002-NPCC-01 and the Drafting Team's supporting document for the Standard's retirement have been merged into one document, and is posted on the NPCC Website for a thirty (30) day pre-ballot review period beginning this date. Immediately following the 30-day pre-ballot review a ten (10) day ballot period will commence. The 30-day Pre-Ballot Review, as currently posted, will close November 15, 2015.

The Standard/supporting document can be viewed at:

Retirement of PRC-002-NPCC-01 Disturbance Monitoring Authorized by NPCC's Regional Standards Committee

If you have any questions, please contact me.

Thank you.

Lee Pedowicz
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NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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March 31, 2016

To: NERC Board of Trustees

Subject: Request for Approval, Retirement of NPCC Regional Reliability Standard PRC-002-NPCC-01 *Disturbance Monitoring.*

On March 23, 2016 in accordance with the NPCC Regional Standard Processes Manual the NPCC Board of Directors approved the retirement of NPCC Regional Standard PRC-002-NPCC-01 *Disturbance Monitoring*.

The subject standard was originally adopted by the NERC Board of Trustees on November 4, 2010 and approved by the FERC on October 20, 2011. The standard was subject to enforcement on October 20, 2013. FERC recently approved the NERC continent-wide standard PRC-002-2 *Disturbance Monitoring and Reporting Requirements*, which becomes enforceable on July 1, 2016. NPCC participated in the development of the continent-wide standard and attributes of the Regional standard were incorporated into PRC-002-2.

Upon approval of the continent-wide standard by the FERC, NPCC's Task Force on System Protection, acting as a standard review/drafting team, initiated an analysis to determine if there was a reliability related need to maintain the Regional standard. The results of the review, as attached, indicated that the continent-wide standard's requirements were sufficient and redundant in their objectives with the Regional standard and identified where any differences are addressed by NPCC's existing more stringent reliability criteria.

Further, in accordance with the NERC "Regional Reliability Standards Evaluation Procedure 2.1", the proposal to retire the standard has been posted by NERC and no non-supportive comments were received.

Accordingly, NPCC is requesting that PRC-002-NPCC-01 be retired effective the later of July 1, 2016 or the date the retirement is approved by the applicable regulatory authorities. Contingent upon the approval of the NERC BOT, NPCC will work with NERC Legal Staff in order to prepare the necessary filings and petitions.

Thank you for your consideration.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
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PRC-002-NPCC-02 Disturbance Monitoring Draft Team Roster

Name:	Company:	Qualifications:
Don Burkart	Con Edison	Don has 5 years in relay protection engineering and have had countless experiences in system event analyses. Additionally, He is the Lead Disciple Engineer for the company wide DME programs.
Robert Grabovickic	National Grid	Responsibilities include the analysis of events and system disturbances, protection co-ordination studies, calculations of settings for protection relays and disturbance fault recorders (DFRs), configuration of DFRs for NY PMU project, reviewing the relay settings of generators owned by customers, the development of protection standards.
Tim Kucey	PSEG	Member of current NPCC PRC-002-NPCC review SDT (joined SDT in 2013 in response to membership solicitation). Co-lead of the “Tools and Training” team of the NERC investigation of the August 2003 Northeast Blackout. Responsible for the bulk of the team’s findings/discoveries – and the associated write-ups in the NERC and US-Canada Bilateral Commission reports - regarding key entities’ implementation, usage and the performance of system monitoring and analysis “tools” (e.g. EMS, RTCAs, SEs) involved in the incident. For the period 1994 through to 2002, technical positions with process and power industry DCS/EMS, SCADA and RTU OEMs: Fisher-Rosemount (now Emerson); Moore Process Control (now Siemens); GE Harris (previously Westronics, HDAP; now GE Power). NERC Manager of Enforcement and Mitigation from 2006 until 2010, then NERC’s CEA agent (Manager of NOP Development) until late 2011. Duties included review of all compliance actions taken by NERC to the NERC BOT Compliance Committee, frequent engagement with the CCC and the Standards Committee, FERC staff, SDTs. Also involvement in several NERC events analyses/investigations and joint NERC-FERC 1B actions, typically involving transmission organizations, balancing authorities and reliability coordinators.
Brian Evans-Mongeon	Utility Services	As a prior member of the drafting team, he believe that he is qualified to serve again. He has been involved in numerous drafting teams including EOP-004, PRC-006 for both NPCC and NERC, BES, and Dispersed Generating Resources. He also serve on the NPCC RCC and the NERC PC, ERSTF, and RBRTF.
Robert Pellegrini	UI	Involved in designing P&C SCADA systems
Jim Watson	Dynergy	He has been employed in the electric utility industry for 33 years in the areas of generation operations, planning, and environmental compliance and for the last 4 years – NERC compliance.
George Wegh	Eversource	George has over 25 years of Electrical Engineering experience, of which 15 years have been in the utility industry. He is presently the Manager of Transmission Protection and Controls Engineering at Eversource Energy. He has been working in the Transmission Protection and Controls Department at Eversource Energy for over 8 years. He presently serve as the NPCC representative on the NERC System Protection and Controls Subcommittee (SPCS) and am Vice Chairman of the NPCC Task Force on System Protection (TFSP).
Paul Difilippo	Hydro One	28 years of experience in various aspects of protection systems at Hydro One including analysis of the 2003 Northeast blackout utilizing all available DME in Ontario. Member of TFSP since 2008 and current Chair. He is also the requester for the RSAR.
Ruida Shu	NPCC	NPCC Standards Staff. Ruida Shu has 8+ years of experience in

		Distribution, Transmission, SCADA, Construction, Daily Electric Operations, Facility Maintenance, Security, DOE/FEMA/APPA Grant Projects, Safety, Compliance and Reliability Standards.
Lee Pedowicz	NPCC	Manager of Reliability Standards at NPCC. Chair of PRC-002-2 Drafting Team. System operations real-time operating and outage scheduling, protective system testing, and substation design experience.
Daniel Kidney	NPCC	NPCC Compliance Staff. Daniel has been a member of the Compliance Enforcement staff at NPCC since 2014. Prior to joining NPCC, he was employed as a Transmission Planner at Central Maine Power.

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December 2nd, 2015

NPCC Full and General Members:

In accordance with the NPCC Regional Standard Processes Manual the ballot period for the retirement of NPCC Regional Standard PRC-002-NPCC-01 Disturbance Monitoring closed at 23:59PM on November 26th, 2015.

The results of the ballot were as follows:

Quorum: 69% of the Total Registered
Approval: 97.10%

No negative ballots were received with comments therefore, in accordance with our Standards Processes Manual a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on February 2, 2016.

Contingent upon the approval of the NPCC BOD, the proposal to retire PRC-002-NPCC-01 will be submitted to the NERC Board of Trustees with subsequent filings with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full retirement record for the standard may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=120

Thank you for your participation.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
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Fax: 212-302-2782
Email: rshu@npcc.org

NPCC Registered Members	1. Determine Quorum				2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**19**	**15**	**0**		**14**	**0**	**1**
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Emera Maine	1	1					1
Eversource	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1			1		
National Grid	1	1			1		
New Brunswick Power Transmission Corporation	1	1			1		
New Hampshire Transmission, LLC	1						
New York Power Authority	1	1			1		
New York State Electric & Gas	1						
Nova Scotia Power Inc.	1	1			1		
NStar Electric Company	1						
Orange and Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1						

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick System Operator	1	1			1		
New York Independent System Operator	1	1			1		

NPCC Registered Members		1. Determine Quorum			2. Vote/Ballot Recording		
		In Attendance	By Proxy		Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**20**	**13**	**0**		**12**	**0**	**1**
Braintree Electric Light Department	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Eversource	1						
Groton Electric Light	1	1			1		
Hingham Municipal Lighting Plant	1	1			1		
Hydro One Inc	1	1			1		
Hydro Quebec Distribution	1	1			1		
Ipswich Municipal Light Department	1						
Long Island Power Authority	1	1			1		
Marblehead Municipal Light Department	1						
National Grid	1	1			1		
New York Power Authority	1						
Orange and Rockland Utilities Inc	1	1			1		
Princeton Municipal Light Department	1	1			1		
Shrewsbury Electric & Cable Operations	1	1			1		
Sterling Municipal Light Department	1						
Toronto Hydro Electric System Ltd.	1						
Vermont Electric Cooperative, Inc.	1						
Wakefield Municipal Gas and Light Department	1	1					1
Westfield Gas & Electric Light Department	1	1			1		

NPCC Registered Members		1. Determine Quorum		2. Vote/Ballot Recording		
		In Attendance (denote w/ 1)	By Proxy (denote w/ 1)	Affirmative (denote w/ 1)	Negative (denote w/ 1)	Abstain (denote w/ 1)
Sector 4, Generator Owners	**22**	**17**	**0**	**17**	**0**	**0**
Consolidated Edison Company of New York, Inc.	1	1		1		
Covanta Energy	1	1		1		
Dominion Resources Inc.	1	1		1		
Dynegy, Inc.	1	1		1		
Entergy Nuclear Northeast	1	1		1		
Eversouce	1	1		1		
Exelon Generation	1	1		1		
First Wind Operations & Maintenance	1	1		1		
International Power America	1					
Long Island Power Authority	1					
Massachusetts Municipal Wholesale Electric Company	1	1		1		
New York Power Authority	1	1		1		
NextEra Energy Resources	1	1		1		
NRG Energy Inc.	1	1		1		
Nova Scotia Power Inc.	1	1		1		
Ontario Power Generation Inc.	1					
PSEG Power Connecticut, LLC	1	1		1		
PSEG Power New York, LLC	1	1		1		
Talen Energy Marketing, LLC	1	1		1		
TransCanada	1					
US Power Generating Company, LLC	1					
Wheelabrator Westchester LP	1	1		1		

NPCC Registered Members		1. Determine Quorum		2. Vote/Ballot Recording		
		In Attendance	By Proxy	Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**14**	**8**	**0**	**8**	**0**	**0**
Brookfield Power Corporation	1	1		1		
Consolidated Edison Company of New York, Inc.	1	1		1		
Consolidated Edison Energy/Development	1					
Constellation New Energy, Inc.	1					
HQ Energy Marketing Inc.	1	1		1		
H.Q. Energy Services (U.S.) Inc.	1	1		1		
Long Island Power Authority	1					
Massachusetts Municipal Wholesale Electric Company	1	1		1		
Nalcor Energy	1					
New York Power Authority	1	1		1		
PSEG Energy Resources & Trade, LLC	1	1		1		
Shell Energy North America	1					
Utility Services Inc.	1	1		1		
Windy Bay Power, LLC	1					

NPCC Registered Members		1. Determine Quorum		2. Vote/Ballot Recording		
		In Attendance	By Proxy	Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 6, State and Provincial Reg. and Govt.	**7**	**4**	**0**	**4**	**0**	**0**
Long Island Power Authority	1	1		1		
Maine Public Utilities Commission	1	1		1		
Massachusetts Attorney General	1	1		1		
New Hampshire Public Utilities Commission	1					
New York Power Authority	1	1		1		
New York State Department of Public Service	1					
Vermont Department of Public Service	1					

NPCC Registered Members		1. Determine Quorum		2. Vote/Ballot Recording		
		In Attendance	By Proxy	Affirmative	Negative	Abstain
		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7, Sub Regional Rel. Councils, REs and	**13**	**7**	**0**	**7**	**0**	**0**
4g Technologies, LP	1					
Ascendant Energy Solutions, Inc.	1					
Energy Sector Security Consortium, Inc.	1					
ERLPhase Power Technologies	1	1		1		
International Business Machines Corporation	1					
McCoy Power Consultants, Inc.	1	1		1		
New York State Reliability Council, LLC	1	1		1		
Oxbow-Sherman Energy, LLC	1	1		1		
PLM, Inc.	1	1		1		
Preti, Flaherty, Beliveau, and Pachios, LLP.	1					
Proven Compliance Solutions, Inc.	1	1		1		
SGC Engineering, LLC	1	1		1		
VIASYN, Inc.	1					

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	19	15	0	15	0.79
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	13	0	13	0.65
4	**Generator Owners**	22	17	0	17	0.77
5	**Marketers, Brokers, Aggragators**	14	8	0	8	0.57
6	**Customers- large and small**	7	4	0	4	0.57
7	**State and Provincial Reg. and Govt. Authorities**	13	7	0	7	0.54
		100	69	0	69	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? YES

Determine if Motion or Item Passes

Sector	Sector Name	Total Registered	Sector % Attending	Affirmative # of Votes	Affirmative Fraction	Negative # of Votes	Negative Fraction	Abstain # of Votes	Votes Cast Total (-Abstentions)	Sector has Voted(1-Y, 0-N)
1	**Transmission Owners**	19	0.79	14	1.000	0	0.000	1	14	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	20	0.65	12	1.000	0	0.000	1	12	1
4	**Generator Owners**	22	0.77	17	1.000	0	0.000	0	17	1
5	**Marketers, Brokers, Aggragators**	14	0.57	8	1.000	0	0.000	0	8	1
6	**Customers- large and small**	7	0.57	4	1.000	0	0.000	0	4	1
7	**State and Provincial Reg. and Govt. Authorities**	13	0.54	7	1.000	0	0.000	0	7	1
	Totals	100		67	7.000	0	0.000	2	67	7

Sum of Affirmative/Number of Sectors that Voted	1.000
MUST BE AT LEAST 2/3 to pass	
Did MOTION PASS?	**PASS**

REGIONAL STANDARDS COMMITTEE

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Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

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Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

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