Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Nominations for the SAR drafting team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30 day comment period March 22 – April 20, 2007.
3. Nominations for the standard drafting team (SDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.

Proposed Action Plan and Description of Current Draft:

The purpose of this standard is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances. This standard will replace PRC-002-1 and PRC-018-1.

The purpose of revising the above standards is to:

1. Ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties; the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
   - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
   - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
   - Version 0 standards development, and
   - Regional Reliability Standards Working Group (RRSWG – a NERC working group involved with regional standards development).

The standard drafting team (SDT) also considered the following additional issues that were not completely captured but were stated or referenced in the above materials.

1. Modify PRC-002-1 to remove RRO in the applicability and eliminate the reference to RRO in PRC-018-1.
2. Create continent wide requirements applicable to Transmission Owners and Generation Owners.
3. The new standard (PRC-002-2) is being proposed based on the requirements of the existing PRC-002-1 and PRC-018-1 standards and a recommendation for replacing both of these existing standards is being proposed. The requirements in PRC-018-1 are being incorporated into PRC-002-2 with the exception of the maintenance and testing requirements in PRC-018-1.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop and post reply comments to initial posting of standard	March 30 – April 20, 2009
2. Post for second 30-day comment period	June, 2009
3. Post for 30-day pre-ballot period.	September, 2009
4. Conduct initial ballot	December, 2009
5. Post response to comments on first ballot	January, 2010
6. Conduct recirculation ballot	February, 2010
7. Board adoption date.	To be determined.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Substation[1] - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modifying its characteristics.

[1] This definition is from IEEE C2-2002

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-2

3. **Purpose:** To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).

4. **Applicability:**

   4.1. Transmission Owners with BES Substation~~s~~ buses having available three phase short circuit ~~MVA~~level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) ~~Facilities rated at 200 kV or above~~

   4.2. Generator Owners ~~with any one of the following~~ connected to ~~the transmission system at 200 kV or above~~BES Substation buses having available three phase short circuit ~~MVA~~level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following~~:~~

   - Generating units having a single generating unit of 500 MVA or higher nameplate rating
   - Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

5. **Effective Date:**

   5.1. 50% of locations/site fully (all the data requirements at the location as identified in RXX elements or all the elements required at the given location) monitored or 50% of the total required monitored elements within three years

   5.2. 100% of locations fully (all the elements required at the given location) monitored and all total monitored elements within six years

   Requirements R1 through R11:

   - The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:
     - Each Responsible Entity shall be at least 50% compliant on monitored equipment
   - The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter four years after Board of Trustees adoption:
     - Each Responsible Entity shall be 100% compliant on monitored equipment.

Requirements R12 and R13

- First day of first calendar quarter eighteen months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

~~Each Transmission Owner and Generator Owner shall record datacollect data at the Transmission switching stations, transmission substations, generating stations, HVAC converter stations, HVDC converter stationslocations that meet the following criteria~~

~~Locations where DM functionality may be required: Transmission switching station, transmission substation, generating station, HVAC converter station, HVDC converter station~~

R1. Each Transmission Owner and Generator Owner shall record (or have a process in place to derive) [A1]the Sequence of Events data for changes in circuit breaker position (open/close) for each of ~~its~~ the circuit breakers- it owns at~~s~~ Transmission switching stations, transmission substations, generating stations, HVAC converter stations, HVDC converter stations that meet the following criteria: ~~BES Substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service). operated at 200 kV and above at each Substation that meets the following criteria:~~

~~**R2.**Contains any combination of three or more transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above.~~

Each[A2] Substation containing any combination of three (3) or more elements, consisting of:

- Transmission lines operated at 200 kV or above
- Transformers having primary and secondary voltage ratings of 200 kV or above.

~~**R2.1.**Connected at 200 kV or above through generating unit step up transformer(s) (GSU(s)) to a generating plant having either a single generating unit of 500 MVA or higher nameplate rating, or through a GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher.~~

Generator Owners connected to -BES Substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following

- Generating units having a single generating unit of 500 MVA or higher nameplate rating
- Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

R2. Each[A3] Generator Owner shall record (or have a process in place to derive) the Sequence of Events data for changes in circuit breaker position (open/close) for ~~its~~ the equipment it owns and connected to BES Substation buses having available three phase short circuit level of 10,000 MVA or above (calculated under normal operating conditions with all facilities and units in service) and either of the following

R2.1. Generating units having a single generating unit of 20 MVA or higher nameplate rating

R2.2. Generating plants with an aggregate plant total nameplate capacity of 75 MVA or higher

~~R2.~~identified in Table 2-1:

Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data	
Location	**Equipment**
Each generating plant having ~~either~~ a single generating unit with a nameplate rating of ~~500~~ 20MVA or higher, and connected to the BES ~~transmission system~~ at ~~200 kV~~10,000 MVA level and above	Each generator output circuit breaker, including low side breakers
Each generating plant with an aggregate plant total nameplate capacity of ~~1500~~ 75 MVA or higher, and connected to the ~~transmission system~~BES at ~~200 kV~~10,000 MVA and above	Each generator output circuit breaker, including low side breakers
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher	Each circuit breaker 200 kV and above
Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	Each circuit breaker 200 kV and above

R3. Each[A4] Transmission[A5] Owner and Generator Owner shall record the time stamp (or have a process in place to derive the time stamp) to within one quarter of a 60 Hz cycle ~~four milliseconds~~[A6] of input received for the change in circuit breaker position (open/close) for each of ~~its~~ their respective circuit breakers specified in Requirements R1 and R2, respectively. [A7]

R4. Each[A8] Transmission Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 4-1:

~~R4.1.~~The three phase to neutral voltages on each monitored line or bus. ~~as follows:~~

- ~~On ring buses, the voltages of bus sections connected to transmission lines.~~
- ~~On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages.~~
- ~~On straight buses, common bus voltages or the individual line voltages.~~

~~**R4.2.**~~**R4.1.** The three phase currents and the residual or neutral currents of each monitored line and transformer.

Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data	
Location	**Equipment owned by Transmission Owner**[A9]
~~Each Substation containing any combination of three (3) or more elements, consisting of transmission lines operated at 200 kV or above; and transformersand transformers having primary and secondary voltage ratings of 200 kV or above~~ Each Substation containing any combination of three (3) or more elements, consisting of: • Transmission lines operated at 200 kV or above • Transformers having primary and secondary voltage ratings of 200 kV or above. (NOTE: 10/7 - MODIFIED AS A RESULT OF OUR DISCUSSION ON QUESTION 9 RESPONSES) Each Substation connected at 200 kV or above through generating unit step up transformer(s) to a generating plant	• Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal • Each transmission bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

having a single generating unit of 500 MVA or higher nameplate rating Each Substation connected at 200 kV or above through generating unit step up transformer(s) to an aggregate plant with a total nameplate capacity of 1500 MVA or higher	

~~R5.~~Each Generator Owner shall record (or have a process in place to derive (TEAM TO CONSIDER REPLACING "DERIVE" WITH "DETERMINE") the following Fault Recording data for its equipment identified in Table 5-1:

~~R5.1.~~The three phase to neutral voltages or phase to phase voltages on Generator Step-up Transformers (GSU(s)) [A10]from the high voltage side or low voltage side of the GSU, or from the generator bus.

~~R5.2.~~The three phase currents of GSU(s) from the high voltage side or low voltage side of the GSU, or from the generator bus.

~~R5.3.~~The neutral current of wye connected GSU(s) high voltage windings.

~~R5.4.~~The three phase to neutral voltages on each monitored line or bus as follows:

- On ring buses, the voltages of bus sections connected to transmission lines.
- On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages.
- On straight buses, common bus voltages or the individual line voltages.

~~R5.5.~~The three phase currents and the residual or neutral currents of each monitored line and transformer.

Table 5-1: Generator Owner's Requirement R5 for Fault Recording Data	
Location	**Equipment**
Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above	Each GSU with a high side of 200 kV and above If multiple GSUs are combined, the voltages and currents may be monitored at the point of interconnection. (NOTE: 10/7 - INSERTED AS A RESULT OF OUR DISCUSSION ON QUESTION 9 RESPONSES)
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	• Each transmission line operated at 200 kV or above that does not have fault data recorded ~~d~~ at its remote terminal • Each bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

10/20 - Triggering methodology – the team will consider adding a requirement that requires responsible entities to have a written triggering methodology

~~R6.~~Each Transmission Owner and Generator Owner shall have Fault Recording data for its equipment identified in Requirements R4 and R5 that conforms to the following:

~~R6.1.~~A single record or multiple records that include the following:

- A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles for the same trigger point

  OR

- At least two cycles of the pre trigger event; the first three cycles of an event; and the final cycle of an event.[A11]

~~R6.2.~~A minimum recording rate of 16 samples per cycle.

~~R7.~~Unless a Transmission Owner has Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4 recorded no further than two Substations away, then for each Substation having a total of seven or more transmission lines connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data:

~~R7.1.~~At least one phase-to-neutral voltage at each voltage level of 200 kV and above.

~~R7.2.~~Frequency (at least one at the required Substation).

~~R7.3.~~At least one phase current (on the same phase and at the same voltage as the voltage monitored in R7.1) (for each line operated at 200 kV and above).

~~R7.4.~~Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (for each line operated at 200 kV and above)

~~R8.~~Each Generator Owner shall record (or have a process in place to derive) the following DDR data at each of its generating plants with an aggregate nameplate rating of 1500 MVA or higher for each GSU that has a transformer high side connected at 200 kV or above:

~~R8.1.~~At least one phase-to-neutral voltage or one phase-to-phase voltage at either the GSU's high side or low side voltage level, or the generator bus voltage.

~~R8.2.~~Frequency (at least one at the required Substation)

~~R8.3.~~At least one phase current (on the same phase and at the same voltage as the voltage monitored in R8.1) or two phase currents for phase-to-phase voltages for each GSU.

~~R8.4.~~Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (per each monitored element) for each GSU.

~~R9.~~Each Transmission Owner and Generator Owner that has DDR devices (to meet Requirement R7 or R8) shall manage its DDR data in accordance with the following technical specifications:

~~R9.1.~~Use the same phase for voltage and current recordings.

~~R9.2.~~Collect at least 960 samples per second to calculate RMS electrical quantities.

~~R9.3.~~Store calculated RMS values of electrical quantities at a rate of at least 6 times per second.

~~R10.~~Each Transmission Owner and Generator Owner that installs a DDR device after January 1, 2011 to meet Requirements R7, R8 and R9 shall install a device that is capable of continuous recording.

~~R11.~~Each Transmission Owner and Generator Owner that has a DDR device (to meet Requirements R7, R8 and R9) that does not have continuous recording capability shall set its device to trigger and record according to the following:

~~R11.1.~~For rate-of-change of frequency.

~~R11.2.~~For oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.

~~R11.3.~~Set data record lengths at a minimum of three minutes.

~~R12.~~Each Transmission Owner and Generator Owner shall synchronize all of its Sequence of Event, Fault Recording, and DDR functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) with the associated hour offset.

~~R13.~~Each Transmission Owner and Generator Owner shall have all recorded Sequence of Event, Fault Recording, and DDR data available (locally or remotely) for 10 calendar days after a Disturbance.

Each Transmission Owner and Generator Owner required to have DMEs shall have a maintenance and testing program for those DMEs that includes:

Maintenance and testing intervals and their basis.

Summary of maintenance and testing procedures.

C. Measures

M1. (To be added later)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

(To be added later.)

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

1.3.1 Each Transmission Owner and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.

1.3.2 Each Transmission Owner and Generator Owner shall each maintain, and report to the Regional Entity, Reliability Coordinator or NERC within 30 calendar days of a request, the following information for Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data:

- Location

- Make and model of equipment
- Type of data source (Sequence of Events, Fault Recording, or Dynamic Disturbance Recording).
- Monitored elements, such as transmission circuit, bus section, circuit breakers, etc.

1.4. Compliance Monitoring and Assessment Processes

(To be added later)

1.5. Additional Compliance Information

1.5.1 Each Transmission Owner and Generator Owner shall meet all of the following criteria when reporting Sequence of Event, Fault Recording , and Dynamic Disturbance Recording data to its Regional Entity, Reliability Coordinator, or NERC:

- All Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data shall be provided to the Regional Entity, Reliability Coordinator, or NERC within 30 calendar days of a request,
- All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111-1999 or successor) files may be used to process and evaluate the data,
- All known delays in interposing relays shall be reported along with the SOE data,
- All data files shall be named in conformance with IEEE C37.232-2007, or its successor, Recommended Practice for Naming Time Sequence Data Files.

2. Violation Severity Levels (To be added later)

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL

E. Regional Variances