Standard Development Timeline

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.
4. The project was placed into informal development the fall of 2010.
5. The project was placed into formal development January 2013.
6. Nominations for two additional SDT members were solicited April 12 – 25, 2013.
7. Three additional SDT members were added May 22, 2013.
8. Industry webinar was held May 22, 2013.
9. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	November 2013
Final Ballot	May 2014
BOT Adoption	August 2014

Effective Dates

See PRC-002-2 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

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 NERC Glossary of Terms (Glossary) used in Reliability Standards 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.

Dynamic Disturbance Recording (DDR) –The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, and abnormal voltage problems.

Fault Recording (FR) –The recording of time sequenced waveform data for short circuits or failure of Elements resulting in abnormal voltage(s) and/or current(s).

Sequence of Events Recording (SOER) –The recording of time sequenced data for change in status of Elements, which may include protection and control devices.

Rationale for Definitions:

The standard addresses the recording (data), not the equipment used to do the recording. The new definitions in the standard for Dynamic Disturbance Recording (DDR), Fault Recording (FR), and Sequence of Events Recording (SOER) specify the recording, not the devices. The devices were not specified because of the proliferation of multiple function devices, and the intent of the Standard is to address the result, not the how the result was achieved.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2. Transmission Owner

4.3. Generator Owner

Rationale for Functional Entities:

The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which Dynamic Disturbance Recording (DDR) is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.

Fault Recording (FR) and Sequence of Events Recording (SOER) locations are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these locations. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available at the bus locations established by the Transmission Owner.

B. Requirements and Measures

R1. Each Transmission Owner shall identify BES bus locations for Sequence of Events Recording (SOER) and Fault Recording (FR). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology*.

1.2. Bus locations shall be assessed at least every five calendar years.

M1. The Transmission Owner has a dated (electronic or hardcopy) list of BES bus locations for Sequence of Events Recording and Fault Recording, identified in accordance with Attachment 1, assessed within the required interval.

Rationale for R1:

SOER and FR data are not required from every location on the BES to conduct adequate analysis of a BES event; SOER and FR from key locations on the BES will suffice. Requirement R1 directs a uniform methodology to select these locations.

Review of actual BES short circuit data received from the industry in response to the DMSDT's June 5, 2013 through July 5, 2013 data request illuminated a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of transmission lines and other devices at the bus, and (iii) the number and size of generating units connected at or near the bus. Buses with a large short circuit MVA level are major contributors to fault currents; these locations have a significant effect on system reliability and performance. Conversely, locations with very low short circuit MVA level seldom cause large system events, so Fault Recording (FR) and Sequence of Events Recording (SOER) typically is not as significant at these locations.

For the purpose of PRC-002-2, a minimum number of locations for FR and SOER are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the SDT developed a procedure included in Attachment 1 – SOER and FR Locations Selection Methodology, that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process.

Each Transmission Owner must re-assess the list of bus locations every five calendar years to account for any system changes such as the addition or removal of large generating resources.

R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the owners of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to owners of Elements established in Requirement R1. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R2:

To ensure effective and timely post-event analysis, it is important to have continuity of SOER and FR, with sufficient data from bus locations across the BES. Of the BES bus locations determined in Requirement R1, there may be locations where the Transmission Owner of the bus location does not own all the Elements. This requirement ensures that all necessary BES Elements at a selected bus location have SOER and FR data available by requiring the Transmission Owner of that bus location to notify the other owners of their respective BES Elements that they require SOER and FR per this standard. A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

R3. Each Transmission Owner and Generator Owner shall have Sequence of Events Recording (SOER) for circuit breaker position (open/close) for each circuit breaker they own connected to the bus locations as per Requirement R2. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M3. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of Sequence of Events Recording for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R3:

Change of state of circuit breaker position, time-stamped, as per Requirement R12 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.

R4. Each Transmission Owner and Generator Owner shall have Fault Recording (FR) to determine the following electrical quantities at the bus locations as per Requirement R2: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Phase-to-neutral voltages for each phase of either each line or bus.

4.2. Each phase current and the residual or neutral current for the following BES Elements:

4.2.1. Transformers that have a low-side operating voltage of 100kV or above.

4.2.2. Transmission lines.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of Fault Recording to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R4:

The required electrical quantities may either be directly measured or derived if sufficient data is measured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required at each location established for either 1) each connected line, or 2) the bus itself. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation.

R5. Each Transmission Owner and Generator Owner shall have Fault Recording (FR) as specified in Requirement R4 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. A single record or multiple records that include:

- 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.
- At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault.

5.2. A minimum recording rate of 16 samples per cycle.

5.3. Trigger settings for at least the following:

5.3.1. Neutral (residual) overcurrent.

5.3.2. Phase undervoltage.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) that Fault Recording meets Requirement R5. Evidence may include, but is not limited to: (1) device specification (R5, Part 5.2) and configuration (R5, Parts 5.1 and 5.3), or (2) actual data recordings or derivations.

Rationale for R5:

Time-stamped pre- and post-trigger fault data aid in the analysis of protection system operations and determination of operation as designed. System faults generally occur for a short time period, approximately 1 to 50 cycles; thus, a 50 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 50 contiguous cycles post-trigger.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point-on-wave data for recreating accurate fault conditions.

R6. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which Dynamic Disturbance Recording (DDR) is required. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. The Elements shall include the following:

6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Demand, inclusive of Requirement R6, Part 6.1, Sub-parts 6.1.2 – 6.1.7.

6.1.2. At least one DDR location in each Responsible Entity's footprint.

6.1.3. Generating resource(s) with:

6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA.

6.1.3.2 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 1000MVA.

6.1.4. Locations necessary to monitor all Elements of:

- Eastern Interconnection - all permanent Flowgates.
- ERCOT Interconnection - major transmission interfaces.
- Hydro-Quebec Interconnection - major transmission interfaces.
- Western Interconnection - all major transfer paths as defined by the Regional Entity.

6.1.5. Both ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter.

6.1.6. Locations necessary to monitor all Elements associated with Interconnection Reliability Operating Limits.

6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding (UVLS) program.

6.**2**. The Elements shall be assessed at least every five calendar years.

M6. The Responsible Entity has a dated (electronic or hardcopy) list of BES Elements for Dynamic Disturbance Recording, identified in accordance with Requirement R6, assessed within the required interval.

Rationale for R6:

The Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR because of the crucial role DDR plays in wide-area disturbance analysis. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system model's performance. The requirement for DDR for identified BES Elements, for the purpose of this standard, is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis.

From its experience with changes to the Bulk Electric System that would affect DDR, the SDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.

R7. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall notify, within 90 calendar days of determination, each Transmission Owner and Generator Owner of the locations and Elements they own for which Dynamic Disturbance Recording (DDR) is required as established in Requirement R6. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M7. The Responsible Entity has dated evidence (electronic or hardcopy) of notification to owners of Elements established in Requirement R6. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R7:

Communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard. The Responsible Entity is only required to share the list of required Elements that each Transmission Owner and Generator Owner owns.

R8. Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each Element they own as per Requirement R7, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. One phase-to-neutral or positive sequence voltage.

8.2. The phase current on the same phase at the same voltage corresponding to the voltage in Requirement R8, Part 8.1, or the positive sequence current.

8.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

8.4. Frequency of any one of the voltage(s) in Requirement R8, Part 8.1.

M8. The Transmission Owner has evidence (electronic or hardcopy) of Dynamic Disturbance Recording to determine electrical quantities as specified in Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R8:

Dynamic Disturbance Recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage.

Because all of the buses within a location are at the same frequencies one frequency measurement is adequate.

R9. Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each Element they own as per Requirement R7, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level.

9.2. The phase current on the same phase at the same voltage in Requirement R9, Part 9.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

9.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

9.4. Frequency of at least one of the voltages in Requirement R9, Part 9.1.

M9. The Generator Owner has evidence (electronic or hardcopy) of Dynamic Disturbance Recording to determine electrical quantities as specified in Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

> Rationale for R9:
>
> A crucial part of wide area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response.

R10. Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording (DDR) as per Requirement R7 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Triggered record lengths of at least three minutes.

10.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- 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 at:
  - No lower than 85% of normal operating voltage for a duration of 5 seconds

M10. Each Transmission Owner and Generator Owner has dated evidence (electronic or hardcopy) of data recording and storage in accordance with Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R10:

Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR an essential component of data collection and event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data are available for the entire Disturbance.

Existing DDR equipment across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R11. Each Transmission Owner and Generator Owner shall have Dynamic Disturbance Recording (DDR), for the Elements as per Requirement R7, which conform to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Input sampling rate of at least 960 samples per second.

11.2. Output recording rate of electrical quantities of at least 30 times per second.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) that Dynamic Disturbance Recording meets Requirement R11. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings (R11, Part 11.2).

Rationale for R11:

Input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

Output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor low frequency oscillations typically of interest during power system disturbances.

R12. Each Transmission Owner and Generator Owner shall time synchronize all Sequence of Events Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) data for the bus locations as per Requirement R2 and Elements as per Requirement R7 to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of time synchronization described in Requirement R12. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings.

Rationale for R12:

Time synchronization of disturbance monitoring equipment allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

R13. Each Transmission Owner and Generator Owner shall provide Sequence of Event Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) data for the bus locations as per Requirement R2 and Elements as per Requirement R7 to the Reliability Coordinator, Regional Entity, or NERC upon request: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. The recorded data will be provided within 30 calendar days of a request.

13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.

13.3. Sequence of Events Recording data will be provided in Comma Separated Value (.CSV) format following Attachment 2.

13.4. Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.

13.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

M13. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) data was submitted upon request in accordance with Requirement R13. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records, (2) device specification and configuration, or (3) actual data recordings.

Rationale for R13:

Multiple entities and data recordings may be involved in wide area disturbance analysis therefore, standardized file format and naming conventions improves timely analysis.

The SDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities how long the data will be available.

R14. Each Transmission Owner and Generator Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and Elements as per Requirement R7, shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording ability.
- Report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.

M14. The Transmission Owner or Generator Owner has dated evidence (electronic or hardcopy) that meets Requirement R14. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, or (3) dated CAP transmittals to the Regional Entity.

Rationale for R14:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures in a reasonable time period to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording ability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) equipment cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must report it to the Regional Entity along with a Corrective Action Plan for returning the equipment to service.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirements R1 and R2, Measures M1 and M2 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R8, Measure M8 for three calendar years.

The Generator Owner shall retain evidence of Requirement R9, Measure M9 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R3, R4, R5, R10, R11, R12, R13, and R14, Measures M3, M4, M5, M10, M11, M12, M13, and M14 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirements R6 and R7, Measures M6 and M7 for five calendar years.

If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 80% but less than 100% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by 30 calendar days or less.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 70% but less than or equal to 80% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 60% but less than or equal to 70% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for less than or equal to 60% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 90 calendar days.

R2	Long-term Planning	Lower	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by 10 calendar days or less.	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Transmission Owner as directed by Requirement R2 was late in notifying one or more owners by greater than 30 calendar days.
R3	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 75% but less than 100% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 50% but less than or equal to 75% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 10% but less than or equal to 50% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented from 0% but less than or equal to 10% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 75% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 50% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 10% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 0% but less

			than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
R5	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R5.
R6	Long-term Planning	Lower	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 80% but less than 100% of the required Elements. OR	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 70% but less than or equal to 80% of the required Elements.	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 60% but less than or equal to 70% of the required Elements.	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for less than or equal to 60% of the required Elements. OR

			The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by 30 calendar days or less.	OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.	OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.	The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 90 calendar days.
R7	Long-term Planning	Lower	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by 10 calendar days or less.	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Responsible Entity as directed by Requirement R7 was late in notifying one or more owners by greater than 30 calendar days.
R8	Long-term Planning	Lower	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to implement DDR as directed by Requirement R8, Parts 8.1 through 8.4.

R9	Long-term Planning	Lower	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to implement DDR as directed by Requirement R9, Parts 9.1 through 9.4.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 75% but less than 100% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 50% but less than or equal to 75% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 0% but less than or equal to 50% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner failed to implement continuous or non-continuous DDR, as directed in Requirement R10, for the Elements they own as determined in Requirement R7.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 75% but less than 100% of the total recording properties as	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 50% but less than or equal to 75% of the total recording	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 10% but less than or equal to 50% of the total recording	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 1% but less than or equal to 10% of the total recording

			specified in Requirement R11.	properties as specified in Requirement R11.	properties as specified in Requirement R11.	properties as specified in Requirement R11.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 90% but less than 100% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 80% but less than or equal to 90% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 70% but less than or equal to 80% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner failed to implement time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for less than or equal to 70% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.

R13	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 90% but less than 100% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 80% but less than or equal to 90% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 70% but less than or equal to 80% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided less than or equal to 70% in the proper data format.

R14	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111-2013, Measuring relays and protection equipment Part 24: Common format for transient data exchange (COMTRADE) for power systems. Standard published 04/30/2013 by IEEE.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

Attachment 1

Sequence of Events Recording (SOER) and Fault Recording (FR)

Locations Selection Methodology

(Requirement R1)

To identify monitored BES bus locations for Sequence of Events Recording and Fault Recording required by Requirement 1 of PRC-002-2, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES bus locations that it owns.

A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid. For example, ring bus or breaker-and-a-half bus configurations are single bus locations.

Step 2. Reduce the list to those locations that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES bus locations on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer bus locations, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 bus locations determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20%.

Step 6. Reduce the BES bus locations on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

a. 1500 MVA or

b. 20% of median MVA level determined in Step 5.

Step 7. If there are no bus locations on the list: the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9.

If the list has 11 or fewer bus locations: Fault Recording and Sequence of Events Recording is required at the BES bus location with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

If the list has more than 11 bus locations: Fault Recording and Sequence of Events Recording is required on at least the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. Fault Recording and Sequence of Events Recording is required at additional BES bus locations on the list determined in Step 6. The aggregate of the number of bus locations determined in Step 7 and this Step will be at least 20% of the bus locations determined in Step 6.

The additional bus locations are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for Fault Recording and Sequence of Events Recording, therefore the following types of BES locations are recommended:

a. Electrically distant bus locations or from other DME devices.
b. Voltage sensitive areas.
c. Cohesive load and generation zones.
d. Bus locations with a relatively high number of incident transmission circuits.
e. Bus locations with reactive power devices.
f. Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored locations for Sequence of Events Recording and Fault Recording for PRC-002-2 Requirement R1 is the aggregate of the bus locations determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SOER) Data Format

(Requirement R13, Part 13.3)

Date	Time	Local Time Offset from UTC	Substation	Device	State[1]
08/27/13	23:58:57.110	EST	Sub 1	Breaker 1	Close
08/27/13	23:58:57.082	EST	Sub 2	Breaker 2	Close
08/27/13	23:58:47.217	EST	Sub 1	Breaker 1	Open
08/27/13	23:58:47.214	EST	Sub 2	Breaker 2	Open

[1] Acceptable states are either OPEN or CLOSE

Guidelines and Technical Basis

High Level Requirement Overview

Requirement	Entity	Identify Bus Locations	Notification	SOER	FR	5 Year Assessment
R1	TO	X		X	X	X
R2	TO		X	X	X	
R3	TO | GO			X		
R4	TO | GO				X	
R5	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R6	RE (PC | RC)	X		X	X
R7	RE (PC | RC)		X	X	
R8	TO			X	
R9	GO			X	
R10	TO | GO			X	
R11	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SOER, FR, DDR Data	SOER, FR, DDR Availability
R12	TO | GO	X		
R13	TO | GO		X	
R14	TO | GO			X

Introduction

The emphasis of PRC-002-2 is not on how Disturbance Monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance Monitoring capability to ensure the completeness of BES data capture.

From a compliance perspective, questions have been raised by industry regarding how conformance to this standard would be judged during a natural disaster which most likely would cause abnormal system conditions for the capturing of data that PRC-002-02 addresses, and also cause the loss of Disturbance Monitoring capability. This is addressed by NERC in its Appendix 4B Sanction Guidelines of the North American Electric Reliability Corporation, Section 2 Basic Principles, Section 2.8 Extenuating Circumstances effective Dec. 20, 2012:

"In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate penalties."

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of system disturbances is important. However, SOER and FR data are not required at every location on the BES to conduct adequate or thorough analysis of a disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuit sallow precise reconstruction of events of both localized and wide-area disturbances.

In addition, more quality information is always better than less when performing event analysis. However, 100% coverage of all elements is not practical or required for effective analysis of wide-area disturbance. Therefore, selectivity of required locations to monitor is important for the following reasons:

1. Identify key locations where crucial information is available when required
2. Excessive overlap of coverage is avoided
3. Avoid gaps in critical coverage
4. Provide coverage of system elements that could propagate a disturbance
5. Avoid mandates to cover system elements that are more likely to be a casualty of a disturbance rather than a cause
6. Establish selection criteria to provide effective coverage in different regions of the continent

Listed as follows, the major characteristics available to determine the selection process are:

1. System voltage level
2. The number of transmission lines into a switchyard
3. The number and size of connected generating units

4. The available short circuit levels

Although it is straightforward to establish a bright line criteria for the application of identified locations, analysis was required to establish a sound technical basis to fulfill the required objectives, rather than using opinions, feelings, or anecdotal judgment based upon experience in one area.

To answer these questions and establish criteria for location of SOER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The team collected information from a wide variety of transmission systems throughout the continent to analyze transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SOER and FR coverage, based solely upon simple, bright-line characteristics, as such the number of lines into a switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Location Selection Procedure was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Location Selection Procedure is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent
2. It is likely to select buses near large generation centers
3. It is likely to select buses where delayed clearing can cause electric system cascading outages
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater system impact

To perform the simple calculations of Attachment 1 of the standard, the following information below is required and the following steps (provided in summary form) are required for systems with more than 11 BES bus locations with three-phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the transmission system under evaluation.
   a. Only tangible switchyard buses are included
   b. Pseudo buses created for analysis purposes in system models are excluded
2. Determine the three-phase short-circuit MVA for each bus.
3. Exclude buses from the list with short circuit levels below 1500 MVA
4. Determine the median short circuit for the top 11 buses on the list (position number 6).
5. Multiply median short circuit level by 20%.
6. Reduce the list of BES buses with short circuit levels higher than 20% of the median
7. Apply SOER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SOER and FR at buses at an additional 10% of the list using engineering judgment, and allowing flexibility to factor in the following considerations.
   a. Electrically distant bus locations from other DME devices

b. Voltage sensitive areas
c. Cohesive load and generation zones
d. Bus locations with a relatively high number of incident transmission circuits
e. Bus locations with reactive power devices
f. Major facilities interconnecting outside the Transmission Owners' area.

There is no requirement for SOER and FR for generating units in this standard. SOER recordings of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). For event analysis purposes, more valuable information is attained about generators and their response to system events pre- and post-contingency through DDR data versus SOER or FR records.

The reassessment interval of five years was chosen based upon experience. Five years is long enough to avoid unnecessary, but long enough to adapt for changing system configurations.

Guideline for Requirement R2: See rationale.

Guideline for Requirement R3:

Analyses of wide-area disturbances often begin by evaluation of SOERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR recordings, since generator loading can be essentially zero regardless of breaker position. SOER of generator breaker operations provide little useful data of generator loading.

Generator Owners are included in this requirement because a Generator Owner may, in some situations, own breakers at the Transmission Owner's bus location. However, buses owned by the Generator Owner will not require SOER because they will not be studied to begin with. Therefore, only Generator Owners who own equipment at the Transmission Owner location may need to implement SOER per PRC-002-2.

Breaker status can be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R14.

Guideline for Requirement R4:

The bus locations for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The Elements connected to those bus locations for which FR data is required include:

- Transmission lines, including interconnection facilities with generating resources
- Transformers

Only those Elements that are included in BES as per the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

Fault recordings are required from each terminal of an Element connected to applicable bus locations.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- The methodology for determining bus locations for (FR) does not include generator buses
- The length of an interconnection between a transmission station and a generating resource is typically short. Current contribution from a generator in case of fault in the transmission system will be captured by fault recording on the transmission station end of the interconnection.
- Faults on the interconnection itself are unlikely. For such faults it is sufficient to have fault current recordings from the transmission station end of the interconnection. Current contribution from a generator is rather deterministic and can be readily calculated if needed.

The SDT, in consultations with NERC's Event Analysis group, determined that DDR from selected generator locations are far more important for event analysis than FRs.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FRs it is possible to determine all fault types. Fault Recordings also augment SOERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a transmission system is well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C \qquad \text{Equation 1}$$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's law. Fault currents for one of the Elements connected to a particular bus location can be derived as a vectorial sum of fault currents recorded at the other Elements connected to that bus location.

Voltage Recordings
There are two options for recording phase-to-neutral voltages at applicable bus locations:

1. <u>At terminals of each line.</u> This option would apply to lines that have full set of VTs/CVTs required for distance protections, which is quite common in practice.
2. <u>At a particular bus</u>, in which case all the Elements connected to that common bus are covered. This option may not be applied that often in practice as it requires full set of phase-neutral VTs/CVTs at the bus.

Guideline for Requirement R5:

This requirement directs the applicable entities to have FR at locations determined per Requirement R1 that meets the following:

Requirement R5, Part 5.1 specifies the minimum amount of Fault Recording data. Pre and post trigger fault data along with the SOE breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection system operations after a fault to determine if the protection system operated as designed. Generally speaking, BES faults and the system response to them occur within a very short time period, approximately 1 to 50 cycles, thus a 50 cycle post trigger record length provides adequate data. Multiple records allow for legacy microprocessor relays which when time synchronized to a common clock are capable of providing adequate fault data but not capable of providing fault data in a single record with 50 cycle post trigger data.

Requirement R5, Part 5.2 specifies the minimum recording rate of FR data. A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER.

Requirement R5, Part 5.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an Oscilloscope or Fault Recording device. The trigger can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R5, Part 5.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R5, Part 5.3.2 specifies a phase under-voltage trigger for phase-phase faults.

Guideline for Requirement R6:

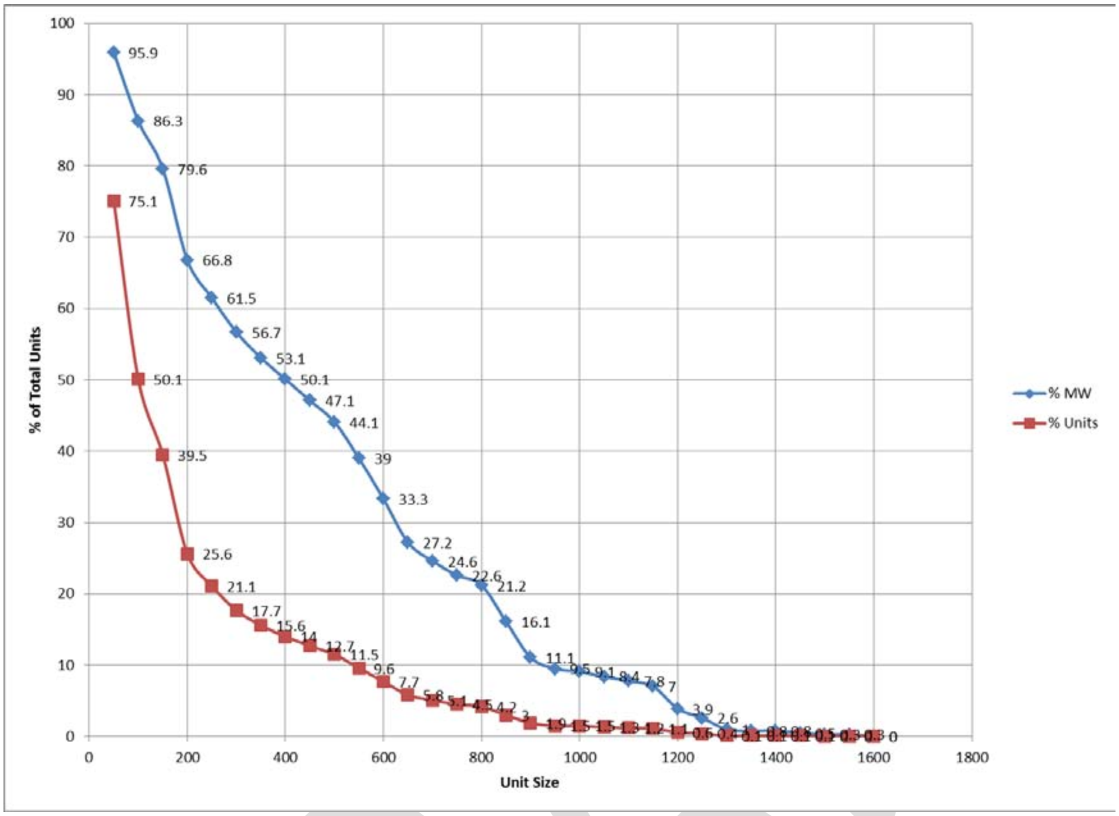
Dynamic Disturbance Recording is used for wide-area disturbance monitoring to determine the system's electromechanical transient and post-transient response and validate system model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the system's dynamic response and ensuring sufficient coverage to determine system performance, DDR is required at key locations in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient locations for DDR coverage for, at a minimum, one location per 3,000 MW of historic peak demand. This number of locations is included to provide adequate system-wide coverage across an Interconnection. To clarify, if any of the key Elements requiring DDR monitoring are within the Responsible Entity's area, these locations are required. If a Responsible Entity (PC or RC) does not have a sufficient number of DDR to meet the one DDR per 3,000 MW of historic peak demand requirement, additional BES Elements must be defined.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide basis for unit size criteria, the DMSDT acquired limited specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which is reporting in 2013 to the NERC GADS program. The team analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The team determined the following basic information about the generating units of interest (current NA fleet i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.
- The information in the spreadsheet does not provide information by which the plant location of each unit can be determined i.e. the team could not use the information to determine which units were located together at a given generation site or facility.

The following figure captures these concepts:



From this information, the team was able to reasonably speculate the generating unit size thresholds proposed in Requirement R6, Part 6.1.3.1 of the standard. The 500MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R6, Part 6.1.3.2 is included to capture larger units located at large generating plants which could pose a stability risk to the system if multiple large units were lost due to electrical or non-electrical contingencies. The incremental impact to the number of units requiring monitoring is expected to be relatively low.

Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. In the Eastern Interconnection, all Flowgates defined in the NERC Book of Flowgates will require DDR *on the metered end of the Flowgate*. However, this data may be calculated, rather than directly measured, if the accurate quantity can be derived (e.g. either end of the Flowgate line could be monitored since the other end could be derived). In the Western Interconnection, these major transmission interfaces are defined by the Regional Entity. In ERCOT and Quebec Interconnections, the Responsible Entity will be required to identify those interfaces that are deemed significant enough to require monitoring (i.e. are utilized for real-time limits such as System Operating Limits or “contingencies”).

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Load. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective location to monitor DDR such that action of the UVLS or voltage instability could be captured on the BES. For example, a major 500kV or 230kV substation on the EHV system close to the load pocket where the UVLS is deployed would likely be a valuable location for DDR coverage and would aid in post-disturbance analysis of the load area's response to large system deviations (voltage, frequency, etc.).

Guideline for Requirement R7: See rationale.

Guideline for Requirement R8:

Dynamic Disturbance Recording measures transient response to system disturbances after fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of Elements defined by the Responsible Entity (PC or RC) in Requirement R6. Voltage recording is required for all expected bus configurations at a given location. For example, a breaker-and-a-half or double bus configuration has a North (or East) Bus and South (or West) Bus, which would require that both buses should have voltage recording, because either can be taken out of service indefinitely. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either bus voltage transformers to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current record is also acceptable. Duplication of current record is not required, because when a line (or a transformer) is out of service its current and power flow records are nil, and do not impact the event analysis process.

For all circuits where current recording is required, real and reactive power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R9:

All Guidelines specified for Requirement R8, equally apply to Requirement R9, too. Since either of the high or low side windings of the generator step-up (GSU) transformer may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As it was explained in the Guideline R8, the system (BES) is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Guideline for Requirement R10:

Large scale system outages are generally an evolving sequence of events that occur over an extended period of time, making DDR an essential component of data collection and event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist at some locations that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R10, Part 10.2:

- Off nominal frequency triggers are used to capture high or low frequency excursions of significant size based on the Interconnection size and inertia.
- Rate-of-change of frequency triggers are used to capture major changes in system frequency which could be caused by large changes in generation or load, or possibly changes in system impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recover (FIDVR) events. A sustained voltage of 85% is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R11:

Dynamic Disturbance Recording contains the dynamic response of power system to a disturbance and is used for analyzing complex power system events. This recording is typically used to capture short term and long term disturbances, such as a power swing. Since the data of interest is changing over the time, Dynamic Disturbance Recording is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in a Fault Recording.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency in sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better representation. In the abnormal conditions of interest (e.g. faults or other disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine-generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R12: See rationale.

Guideline for Requirement R13:

This requirement directs the applicable entities that upon requests from the Reliability Coordinator, Regional Entity or NERC to provide SOER, FR data for locations determined in requirement R1 and DDR data for Elements determined per requirement R6. To facilitate the analysis of BES disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R13, Part 13.1 specifies the maximum timeframe of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor.

Requirement R13, Part 13.2 specifies that the minimum time period of 10 calendar days that the data will be retrievable preceding a request. With the equipment in use that has the capability of making a recording, having the data retrievable for the 10 calendar days preceding a request is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days.

Requirement R13, Part 13.3 specifies a Comma Separated Value (.CSV) format per Attachment 2 for the SOER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power system disturbance.

Requirement R13, Part 13.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange it is well established in the industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance.

Requirement R13, Part 13.5 specifies the IEEE C37.232 COMNAME format for the naming the data files of the SOER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files first version was approved in 2007. From the August 14, 2003 blackout there was thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and because of that it became difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in their initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of their top ten recommendations.

Guideline for Requirement R14:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the existence of equipment used for SOER, FR, and DDR, at the bus locations which had been established in Requirement R1, which are found to be out of service. The owners are to endeavor to return the equipment to service within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a reasonable amount of equipment out of service does not result in lack of sufficient data for coverage of the system. Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to return the equipment to service within 90 calendar days, the requirement further provides that, for such cases, the entity must report such occasions to the Regional Entity and also provide a Corrective Action Plan. These actions are considered to be the appropriate level of due diligence needed to provide for a robust and adequate data availability.