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 Disturbance Monitoring Standard Drafting Team (~~SDT~~DMSDT) 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~~DMSDT members were solicited April 12 – 25, 2013.
7. Three additional ~~SDT~~DMSDT 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.
10. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders

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

Effective Dates

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~See PRC-002-2~~

Implementation Plan.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.

Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.

- **Note**: Entities that own only one (1) identified BES bus, BES Element, or generating unit and are notified by an entity shall be 100% compliant within four (4) years following notification.

Entities shall be 100% compliant with a reassessed list from Requirement R1or R5 within three (3) years following notification of the list.

Version History

Version	Date	Action	Change Tracking
2.0	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.

None

When this standard has received ballot approval, the ~~text boxes~~Rationale Boxes will be moved to the ~~Application~~ Guidelines and technical Basis 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.

~~3.~~4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

~~3.1.1~~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) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

~~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 Recorder (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.~~

~~BES Buses where Fault Recorder (FR) and Sequence of Events Recorder (SOER) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available.~~

B. Requirements and Measures

R1. Each Transmission Owner shall identify BES buses for which sequence of events ~~recorder~~recording (SER) and fault ~~recorder~~recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify ~~within 90 calendar days~~ other owners~~, if any,~~ of BES Elements connected to those BES buses~~.~~, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data, and reevaluate the identified BES buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. The Transmission Owner has a dated (electronic or ~~hardcopy~~hard copy) list of BES buses for which SER and FR data are required, identified in accordance with Attachment 1, ~~assessed~~and evidence that the bus identification has been reevaluated within the required interval. The Transmission Owner will also have dated (electronic or ~~hardcopy~~hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Requirement R1 directs a uniform methodology to identify these BES buses. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) 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 Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on system reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause large cascading system events, so SER and FR data from these BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.

For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data are required, based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and system topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data are required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. SER and FR data will include generating resource contributions to an event. DDR data better shows generator response to disturbances.

Each Transmission Owner must reevaluate the list of BES buses every five calendar years to address system changes.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

~~Rationale for R1:~~

~~SER and FR data are not required from every location on the BES to conduct adequate analysis of a BES event; SER 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 Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. Buses with a large short circuit MVA level Elements that have a significant effect on system reliability and performance. Conversely, buses with very low short circuit MVA level seldom cause large cascading system events, so FR and SER typically are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected locations. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.~~

~~For the purpose of PRC-002-2, there are a minimum number of buses for which FR and SER are required based on the short circuit level, With these concepts and the objective being sufficient recording coverage for event analysis, the SDT developed a procedure included in Attachment 1, that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for FR and SER data regardless of variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process.~~

~~BES buses where FR and SER data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. SER and FR data will reflect generating resource contributions to an event. DDR data better shows generator response to disturbances.~~

~~Each Transmission Owner must reevaluate the list of buses every five calendar years to address system changes such. Since there may be multiple owners of equipment that comprise a bus, the notification required in R1 is necessary to ensure all owners are notified.~~

~~To ensure effective and timely post-event analysis, it is important to have continuity of SER 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 SER 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.~~

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker they own connected directly to the BES buses identified ~~per~~in Requirement R1 and associated with the BES Elements at those BES buses identified ~~per~~in Requirement R1. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which can include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R2:

The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance. Other status monitoring indications can be used for devices other than circuit breakers.

~~Rationale for R3:~~

~~The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, timestamped, as per Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.~~

R3. Each Transmission Owner and Generator Owner shall have the following FR data to determine the following electrical quantities ~~at~~for each of the BES Elements they own connected to the BES buses identified ~~per~~in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltages for each phase of each specified ~~line or~~ BES bus.

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

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

3.~~2.~~2.2 Transmission lines.

M3. ~~**M3.**~~ The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of FR data is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations including a single design standard as a representation for common installations; or (2) actual data recordings or derivations.

~~Rationale for R4:~~

~~The required electrical quantities may either be directly measured or derived if sufficient FR data is captured (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 to be determinable for each BES Bus identified in Requirement R1. 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. For transformers (Part 3.2.1), the data may be from either the high side or the low side of the transformer.~~

Rationale for R3:

The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured (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 to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for system disturbance analysis. 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. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 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 30 cycles for the same trigger point~~.~~, or
- At least two cycles of the pre-trigger data, the first three cycles of the ~~fault~~post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2~~.~~ A minimum recording rate of 16 samples per cycle.

4.3~~.~~ Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) that FR data meets Requirement ~~R5~~R4. Evidence may include, but is not limited to: (1) device specification (R4, Part 4.2) and configuration (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

~~Rationale for R4:~~

~~Time-stamped pre- and post-trigger fault data aid in the analysis of power system operations and determination if operation were as designed. System faults generally persist 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.~~

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power system operations and determination if operations were as designed. System faults generally persist for a short time period, thus, a 30 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 30 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.

R5. Each Responsible Entity ~~(Planning Coordinator or Reliability Coordinator, as applicable)~~ shall identify BES Elements for which dynamic disturbance ~~recorder~~recording (DDR) data is required, notify ~~within 90 calendar days~~ other owners~~,~~ ~~if any,~~ of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. The BES Elements shall include the following:

5.1.1. Generating resource(s) with:

- ~~5.1.1.1.~~ Gross individual nameplate rating greater than or equal to 500 MVA~~.~~, or
- ~~5.1.1.2~~ Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to ~~1000MVA.~~ 1000 MVA.

5.1.2. Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:

- Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or
- Transfer Paths in the Western Interconnection Path Rating Catalog, or
- Voltage stability limited transfer paths or load serving area, or
- Interfaces between Balancing Authority Areas, or
- Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC~~)~~).

5.1.3. Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements associated with Interconnection Reliability Operating Limits~~.~~ (IROLs).

5.1.5. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.

5.2. The BES Elements shall include a minimum of:

5.2.1 One BES Element.

5.2.2 One additional BES Element ~~per~~for each additional 3,000 MW of its historical peak system Demand.

M5. The Responsible Entity has a dated (electronic or ~~hardcopy~~hard copy) list of BES Elements for DDR data, identified in accordance with Requirement R5, assessed within the required interval, dated evidence (electronic or ~~hardcopy~~hard copy) of notification to each Transmission Owner or Generator Owner of Elements identified in Requirement R5. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR plays a crucial role in wide-area disturbance analysis, and the Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR data capture. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system performance. The requirement for DDR data 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 DMSDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.

The DDR data is to be captured for a BES Element, and with the exception of HVDC, is obtainable from one terminal of an Element. This pertains to "major transmission interfaces".

For HVDC (Part 5.1.3), each Transmission Owner is only responsible for DDR data for the Elements that it owns.

Part 5.1.5 is intended to have DDR data for at least one BES Element in a portion of the BES with a voltage response for system events that has required the installation of a UVLS.

It is intended that a Responsible Entity will have DDR data for one BES Element and one additional BES Element for each 3,000 MW of its historical peak system Demand.

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.

~~Rationale for R5:~~

~~DDR plays a crucial role in wide area disturbance analysis, and the Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR data capture. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system 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.~~
~~The DDR data is to be captured for a BES Element, and with the exception of HVDC, is obtainable from one terminal of an Element.~~

~~For HVDC (Part 5.1.3), each Transmission Owner is only responsible for DDR data for the Elements that it owns.~~

~~Sub-Part 5.1.5 is intended to have DDR data for at least one BES Element in a portion of the BES with a voltage response for system events that has required the installation of a UVLS.~~

~~It is intended that a Responsible Entity will have DDR data for one BES Element, and one more BES Element for each 3,000 MW of its historical peak system Demand.~~

~~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.~~

R6. Each Transmission Owner shall have DDR data for each BES Element ~~they own~~it owns for which it received notification as ~~per~~identified in Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

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

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or ~~hardcopy~~hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. 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 R6:

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. The electrical quantities can be determined (calculated, derived, etc.).

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

The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

~~Rationale for R6:~~

~~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. The electrical quantities can be determined--calculated, derived, etc.~~

~~Because all of the buses within a location are at the same frequencies one frequency measurement is adequate. The data requirements for PRC-002-2 are based on a system configuration assuming all normally-closed circuit breakers on a bus are closed.~~

R7. Each Generator Owner shall have DDR data for each BES Element ~~they own as per~~it owns and is notified according to Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 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.

7.2 The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

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

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. –The Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of DDR data to determine electrical quantities as specified in Requirement ~~R9~~R7. 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 R7:~~

~~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. This standard defines the 'what' of DDR, not the 'how.' GOs may install this capability or, where the TO already has suitable DDR data, contract with the TO. However, the Generator Owner is still responsible for the provision of this data.~~

Rationale for R7:

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. This standard defines the 'what' of DDR, not the 'how.' Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner ~~that is~~ responsible for DDR data ~~as per~~in Requirement R5 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]*

~~-~~**8.1** Triggered record lengths of at least three minutes.

8.2.~~–~~ At least one of the following three triggers:

- Off nominal frequency trigger set at:

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

- Rate of change of frequency trigger set at:

Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds.

~~no lower than 85% of normal operating voltage for a duration of 5 seconds~~

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or ~~hardcopy~~hard copy) of data recording and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R8:

Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for 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 is available for the entire event.

Existing DDR data recording 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).

~~Rationale for R8:~~

~~Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for 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 recording 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).~~

R9. Each Transmission Owner and Generator Owner in Requirement R5 shall have DDR data~~, for the Elements as per Requirement R5, which conform~~ that conforms to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

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

M9. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An 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.

An 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 the low frequency oscillations typically of interest during power system disturbances.

~~Rationale for R9:~~

~~An 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.~~

~~An 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.~~

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR and DDR data for the BES ~~bus~~ buses identified ~~per~~in Requirement R1 and BES Elements identified ~~per~~in Requirement R5 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]*

M10. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy)~~hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings, or (3) station drawings.

~~Rationale for R10:~~

~~Time synchronization of disturbance monitoring data 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.~~

~~Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.~~

Rationale for R10:

Time synchronization of disturbance monitoring data 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.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

R11. Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES ~~bus locations~~buses identified ~~per~~in Requirement R1 and BES Elements identified ~~per~~in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

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

11.3. SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2.

11.4. ~~.~~ FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.

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

M11. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) data was submitted upon request in accordance with Requirement R11. 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 R11:

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

The DMSDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload.

For Part 11.2, the DMSDT intends for data to be available for 10 days preceding a request for that data. Requests are usually initiated the same or next day following an event for which data is requested. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requester of data has to be aware of the Part 11.2 10 day retrievability. Realistic overwrite concerns may have to consider the recording capability implemented.

Part 11.4 specifies the IEEE C37.111-2013 COMTRADE format for the FR and DDR data. IEEE C37.111 is the Standard for Common Format for Transient Data Exchange, and it is well established in 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. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER ~~and~~, FR ~~data at the BES buses identified per Requirement R1~~ or DDR data ~~for the BES Elements identified per Requirement R5, shall~~, restore the recording capability or develop a timeline for restoration and a Corrective Action Plan (CAP ~~), to be submitted~~) for submission to the Regional Entity ~~, to restore the recording ability which includes a timeline for the restoration.: [~~ :[*Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or ~~hardcopy~~hard copy) that meets Requirement R12. 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 R12:~~

~~Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days 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) 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. The timeline required for the CAP depends on the entity and they type of data required. For example, DDR data from a generator may not be restored until the next outage cycle. A CAP is not necessary if the recording capability is restored within 90 day of the discovery of the failure.~~

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording capability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. For example, DDR data from a generator may not be restored until the next outage cycle.

~~Rationale for R11:~~

~~Multiple entities and data recordings may be involved in wide area disturbance analysis. 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.~~

~~For Part 11.2, the SDT intends for data to be available for 10 days preceding a request for that data. Requests are usually initiated the same or next day following an event for which data is requested. A 10 calendar day time frame provides a practical limit on the amount of data required to be stored and lets the requesting entities how long the data will be available. The requester of data has to be aware of the Part 11.2 10 day retrievability.~~

~~Realistic overwrite concerns may have to consider the recording capability implemented.~~

~~Part 11.4 specifies the IEEE C37.111-2013 COMTRADE format for the FR and DDR data. IEEE C37.111 is the Standard for Common Format for Transient Data Exchange, and 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. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.~~

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 Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

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

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 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 BES buses as directed by Requirement R1 for more than 80% but less than 100% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 70% but less than or equal to 80% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 60% but less than or equal to 70% of the required BES buses. OR The Transmission Owner assessed the BES buses- as directed by Requirement R1 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by	The Transmission Owner identified the BES buses as directed by Requirement R1for less than or equal to 60% of the required BES buses-. OR The Transmission Owner assessed the BES buses as directed by Requirement R1but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying one or more other owners by

				greater than 10 calendar days but less than or equal to 20 calendar days.	greater than 20 calendar days but less than or equal to 30 calendar days.	greater than 30 calendar days.
R2	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 75% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 50% but less than or equal to 75% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 10% but less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had from 0% but less than or equal to 10% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 75% but less than 100% of the total	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 50% but less than or equal to 75% of	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 10% but less than or equal to 50% of	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0% but less than or equal to 10% of

			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~~for each BES Element.	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~~for each BES Element.	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~~for each BES Element.	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~~for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 80% but less than 100% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for less than or equal to 60% of the required BES Elements. OR

			The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by 30 calendar days or less. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by 10 calendar days or less.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying one or more owners by greater than 30 calendar days.
R6	Long-term Planning	Lower	The Transmission Owner- had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for	The Transmission Owner failed to ~~had~~have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			applicable BES Elements.	all applicable BES Elements.	all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 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 had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 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 have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 75% but less than 100% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 50% but less than or equal to 75% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 0% but less than or equal to 50% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 75% but less than 100% of the total recording properties as	The Transmission Owner or Generator Owner had DDR data that meets more than 50% but less than or equal to 75% of the total recording	The Transmission Owner or Generator Owner had- DDR data that meets more than 10% but less than or equal to 50% of the total recording	The Transmission Owner or Generator Owner had DDR data that meets ~~more than 1% but~~ less than or equal to 10% of the total recording

			specified in Requirement R9.	properties as specified in Requirement R9.	properties as specified in Requirement R9.	properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 90% but less than 100% of the ~~bus locations as per Requirements~~BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization for SER, FR, and DDR data for less than or equal to 70% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.

R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 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 R11, Part ~~113~~11.2 provided more than 90% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 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 R11, Part 11.2 provided more than 80% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 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 R11, Part 11.2 provided more than 70% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 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 R11, Part 11.2 failed to provide less than or equal to

			100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% of the data but less than 100% of the data in the proper data format.	or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% of the data but less than or equal to 90% of the data in the proper data format.	or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% of the data but less than or equal to 80% of the data in the proper data format.	70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 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 R12 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 R12 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.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

~~NERC~~U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003~~,~~ Blackout ~~Final NERC Report~~in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout~~, November~~ in the United States and Canada (Nov. 2003~~, in the United States and Canada~~)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events ~~Recorder~~Recording (SER) and Fault ~~Recorder~~Recording (FR) Data

~~Locations Selection Methodology~~

(Requirement R1)

To identify monitored BES ~~bus locations~~buses for Sequence of Events ~~Recorder~~Recording (SER) and Fault ~~Recorder~~Recording (FR) data 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 buses that it owns.

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

Step 2. Reduce the list to those BES buses 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 buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer ~~bus locations~~buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

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

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

- 1500 MVA or
- 20% of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

If the list has more than 11 BES buses: ~~FR~~SER and ~~SER~~FR data is required on at least the 10% of the BES buses, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. ~~FR~~SER and ~~SER~~FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20% of the BES ~~bus~~buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for ~~FR~~SER and ~~SER~~FR data, therefore the following types of BES buses are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored ~~locations~~BES buses for ~~FR~~SER and ~~SER~~FR data for ~~PRC-002-2~~ Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events ~~Recorder~~Recording (SER) Data Format

(Requirement R11, Part 11.3)

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". Other status monitoring indications can be used for devices other than circuit breakers.

Guidelines and Technical Basis

High Level Requirement Overview

Requirement	Entity	Identify ~~Bus Locations~~ BES Buses	Notification	SER	FR	5 Year Assessment
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

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."~~

The data requirements for PRC-002-2 are based on a system configuration assuming all normally~~-~~ closed circuit breakers on a bus are closed.

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of system disturbances is important. However, SER and FR data are not required at every ~~location~~BES bus 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~~BES buses to monitor is important for the following reasons:

1. Identify key ~~locations~~BES buses 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~~The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of transmission lines into a substation or 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~~BES buses, 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~~BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The ~~team~~MVA 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 SER and FR coverage, based solely upon simple, bright-line characteristics, such as the number of lines into a substation or 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~~Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

~~The Location Selection Procedure~~The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) data 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~~buses with three~~-~~ phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the transmission system under evaluation.
   a. Only tangible substation or 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 SER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SER 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~~BES buses or electrically distant from other DME devices
   - ~~b.~~ Voltage sensitive areas
   - ~~c.~~ Cohesive load and generation zones
   - ~~d. Bus locations~~BES buses with a relatively high number of incident transmission circuits
   - ~~e. Bus locations~~BES buses with reactive power devices
   - ~~f.~~ Major facilities interconnecting outside the Transmission Owners' area.

~~There is no requirement for SER and FR for generating units in this standard.~~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 SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). ~~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 SER or FR records~~As a result, this standard only requires DDR data.

The reevaluation interval of five years was chosen based upon the experience~~. Five years is long enough to avoid unnecessary reevaluations, but long enough~~ of the DMSDT to address changing system configurations~~.~~ while creating balance in the frequency of reevaluations.

Guideline for Requirement ~~R3~~R2:

Analyses of wide-area disturbances often begin by evaluation of SERs 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 data, since generator loading can be essentially zero regardless of breaker position. SER ~~of~~data for generator breaker operations provides little useful data of generator loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers ~~at~~connected to the Transmission Owner's bus~~ location. ~~.

Guideline for Requirement R3:

The BES buses 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~~BES buses for which FR data is required include:

- ~~Transmission lines, including interconnection facilities with generating resources~~
- Transformers with a low-side operating voltage of 100kV or above
- Transmission lines

Only those Elements that are identified as BES as ~~per~~identified in 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.

FR data must be determinable from each terminal of ~~an~~a BES Element connected to applicable BES buses.

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

- Current contribution from a generator in case of fault ~~in~~on the transmission system will be captured by FR data on the transmission system.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The ~~SDT~~DMSDT, after ~~consultating~~consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

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~~FR data it is possible to determine all fault types. FR data also ~~augment~~augments SERs 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 generally 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:

$$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$$ ~~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~~Law. Fault currents for one of the BES Elements connected to a particular BES bus ~~location~~

can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus ~~location~~.

Voltage Recordings

Voltages are to be recorded at applicable BES buses. Note that the Requirement calls for the voltages to be determinable. There are two options for recording phase-to-neutral voltages at applicable ~~bus locations~~BES buses:

1. At terminals of each line. This option would apply to lines that have a full set of VTs/CVTs required for distance protections, which is quite common in practice.
2. At a particular BES bus, in which case all the BES Elements connected to that common BES bus are covered.

Guideline for Requirement R4:

This requirement directs the applicable entities having FR determined ~~per~~as identified in Requirement R1 that meets the following:

Requirement R4, Part 4.1 specifies the minimum amount of FR data. Pre- and post~~-~~-trigger fault data along with the SER 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~~a 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 30 cycles, thus a 30 cycle post-trigger record length captured 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 ~~53~~30 cycle post trigger data.

Requirement R4, Part 4.2 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 SER.

Requirement R4, Part 4.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an ~~Oscilloscope~~oscilloscope or ~~Fault Recording~~FR 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 R4, Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data 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~~for key ~~locations~~BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historic peak Demand. This DDR data is included to provide adequate system~~-~~ wide coverage across an

Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage ~~should~~had to be specified.

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

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

From this information, the ~~team~~DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA~~.~~”. The ~~500MVA~~500 MVA 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 R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the system if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The ~~300MVA~~300 MVA threshold was chosen based on the ~~Team’s~~DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. The incremental impact to the number of units requiring monitoring is expected to be relatively low. ~~Wording was added to cover combined cycle plants, in which the loss of one unit will lead to the loss of a companion unit within a very short period of time. Because of the loss of the entire combined cycle plant, 500MVA was chosen as the threshold.~~

Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. 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 the 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”). Only one BES Element associated with a major transmission interface needs DDR data capability.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective ~~location~~BES Element to monitor for 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~~BES Element for DDR coverage and would aid in post-disturbance analysis of the load area’s response to large system deviations (voltage, frequency, etc.). It is ~~not~~ intended to have DDR data for ~~all areas affected by~~ “Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.”

Guideline for Requirement R6:

DDR data shows 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 BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. 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 with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources 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.

It must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally~~-~~ closed circuit breakers on a bus are closed.

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.

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 R7:

All Guidelines specified for Requirement R6, ~~-~~apply to Requirement R7~~, 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 for R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally~~-~~ closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Large scale system outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for 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 BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist ~~at~~for some ~~locations~~BES Elements 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 R8, Part 8.2:

- 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 Recovery (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 R9:

DDR data contains the dynamic response of a 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 time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in ~~Fault Recorder~~FR data.

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 the 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 ~~R110:~~ ~~See rationale.~~R10: Time synchronization of disturbance monitoring data 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.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

Guideline for Requirement R11:

This requirement directs the applicable entities that upon requests from the Reliability Coordinator, Regional Entity or NERC to provide SER, FR data for BES buses determined in requirement R1 and DDR data for BES Elements determined per requirement R5. 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 R11, Part 11.1 specifies the maximum ~~timeframe~~time frame 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 R11, Part 11.2 specifies that the minimum time period of 10 calendar days ~~that~~for which the data will be retrievable preceding a request. With the equipment in use that has the capability of ~~making a~~ recording data, 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. To clarify the 10 calendar day time frame, an incident occurs on a Day 1. If a request for data is made on Day 6, then that data has to be provided to the requester within 30 calendar days. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part ~~1~~11.3 specifies a Comma Separated Value (.CSV) format ~~per~~according to Attachment 2 for the SER 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 R11, Part 11.4 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. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

Requirement R11, Part ~~1~~11.5 specifies the IEEE C37.232 COMNAME format for the naming the data files of the SER, 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~~its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of ~~their~~its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and ~~Generator~~generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements which had been established in Requirements R1 and R5 and are found to be out of service. The owners are to return the capability 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 capability 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 capability to service within 90 calendar days, the requirement further provides that, for such cases, the entity must ~~provide~~develop a timeline and a Corrective Action Plan (CAP) for submission to the Regional

Entity. These actions are considered to be appropriate to provide for robust and adequate data availability.