Supporting Statement
FERC-725G, Mandatory Reliability Standards

The existing information collection requirements in the currently effective Mandatory Reliability Standards, are approved by OMB under FERC-725G, Mandatory Reliability Standards for the Bulk-Power System: PRC Standards; PRC-002-4.

1. CIRCUMSTANCES THAT MAKE THE COLLECTION OF INFORMATION NECESSARY

On August 8, 2005, The Electricity Modernization Act of 2005, which is Title XII of the Energy Policy Act of 2005 (EPAct 2005), was enacted into law[1]. EPAct 2005 added a new section 215 to the Federal Power Act (FPA), which requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.

Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[2] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently.[3] In 2006, the Commission certified NERC (North American Electric Reliability Corporation) as the ERO[4] pursuant to section 215 of the FPA.[5]

On March 16, 2007 (pursuant to section 215(d) of the FPA), the Commission issued Order No. 693, approving 83 of the 107 initial Reliability Standards filed by NERC. Order 693 addressed several Reliability Standards. In the intervening years, numerous changes have been made to update, eliminate, or establish various Reliability Standards.

2. HOW, BY WHOM, AND FOR WHAT PURPOSE THE INFORMATION IS TO BE USED AND THE CONSEQUENCES OF NOT COLLECTING THE INFORMATION

In general, information collection and record retention requirements related to Reliability Standards are not submitted to, or retained for audit by, FERC. Rather they are submitted to, or retained for audit by, NERC or the Compliance Enforcement Authority, as specified in each

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1 The Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), codified at 16 U.S.C. 824o (2006).

2 *Id.* 824o(c), (d).

3 *Id.* 824o(e).

4 "Electric Reliability Organization" or "ERO" means the organization certified by the Commission the purpose of which is to establish and enforce Reliability Standards for the Bulk-Power System, subject to Commission review.

5 *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

individual Reliability Standard. Without collecting this information, reliability of the bulk-power system could become compromised, potentially resulting in outages.
Section 215 of the Federal Power Act (FPA)[6] requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. The Commission has certified the North American Reliability Corporation (NERC) as the ERO. In addition, a Regional Entity may propose Reliability Standards to be effective in that region.[7] Once approved, Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently.

Formerly:

> PRC-002-3 is applicable to the RC, TO and GO and NERC modified the applicability of the PRC-002-3 standard to remove PCs as a responsible entity subject to the standard and replace any references in the standard that would have included PCs with references to RCs. NERC concluded that the RC was the appropriate entity to carry out the duties that currently apply to PCs in certain interconnections, including the identification of BES elements that are part of an IROL or stability-related SOL.

Currently:

> PRC-002-4, (Disturbance Monitoring and Reporting Requirements), the associated Violation Risk Factors and Violation Severity Levels, and the proposed implementation plan including the retirement of the currently effective Reliability Standard PRC-002-3, proposed by the North American Electric Reliability (NERC) in a petition dated March 10, 2023. NERC also proposed the retirement of Reliability Standard PRC-002-3. The Commission included the petition in a Combined Notice of Filings published on March 23, 2023, at 88 FR 17564.
> Mandatory Reliability Standards for the Bulk-Power System: PRC Reliability Standards NERC's proposed revisions: (1) clarify requirements for notifications under the standard, including when generator owners and transmission owners must have data for an applicable transformer or transmission line; (2) clarify and make consistent terminology used in the Standard; (3) incorporate the implementation timeframe for newly-identified facilities; and (4) add a criterion defining substantial changes in fault current levels requiring changing the locations for which certain data is recorded.

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requirements and Measurements

R1. Each Transmission Owner shall

1.1. Identify BES buses for which sequence of events recording (SER) and fault

recording (FR) data is required by using the methodology in PRC-002-4,

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6 16 U.S.C. 824o

7 16 U.S.C. § 824o(e)(4). A Regional Entity is an entity that has been approved by the Commission to enforce Reliability Standards under delegated authority from the ERO. *See* 16 U.S.C. § 824o(a)(7) and (e)(4).

Attachment 1.

1.2. Notify the other owners of BES Elements directly connected1 to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses

1 For the purposes of this standard, “directly connected” BES Elements are BES Elements connected at the same

voltage level within the same physical location sharing a common ground grid with the BES bus identified under

Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

M2. The Transmission Owner or Generator Owner has evidence (electronic or 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 may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns directly connected to the BES buses identified in Requirement R1

3.1. Phase-to-neutral voltage for each phase of each specified BES bus.

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

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

3.2.2. Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that 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 which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following

4.1. A single record or multiple records that include:

• A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or

• At least two cycles of the pre-trigger data, the first three cycles of the posttrigger 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 hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Reliability Coordinators shall

5.1. Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1. Generating resource(s) with:

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

5.1.1.2. Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2. Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

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

5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

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

5.2. Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1. One BES Element; and

5.2.2. One BES Element per 3,000 MW of the Reliability Coordinator’s historical simultaneous peak System Demand.

5.3. Notify all owners of identified BES Elements, within 90 calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.

M5. The Reliability Coordinator has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Reliability Coordinator has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

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

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

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

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

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

M6. The Transmission Owner has evidence (electronic or 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, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [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 transformer (GSU) high-side or low-side voltage level.

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

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

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

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.

8.1. Triggered record lengths of at least three minutes.

8.2. At least one of the following three triggers:

• Off nominal frequency trigger set at:

Low High

o Eastern Interconnection <59.75 Hz >61.0 Hz

o Western Interconnection <59.55 Hz >61.0 Hz

o ERCOT Interconnection <59.35 Hz >61.0 Hz

o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz

• Rate of change of frequency trigger set at:

o Eastern Interconnection < -0.03125 Hz/sec >0.125 Hz/sec

o Western Interconnection < -0.05625 Hz/sec >0.125 Hz/sec

o ERCOT Interconnection < -0.08125 Hz/sec >0.125 Hz/sec

o Hydro-Quebec Interconnection < -0.18125 Hz/sec >0.1875 Hz/sec

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

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data

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 hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

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

10.1. Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2. Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10.The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC

11.1. Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.

11.2. Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.

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

11.4. FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11.The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that 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) documents describing data storage capability, device specification, configuration, or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data

• Restore the recording capability, or

• Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12.The Transmission Owner or Generator Owner has dated evidence (electronic or 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, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

R13. Each Transmission Owner and Generator Owner shall

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

Attachment 1

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

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, 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 includes physical buses with breakers 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.

Step 2. Reduce the list to those BES buses that have a maximum available calculated Three-phase short circuit MVA of 1,500 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 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 percent.

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:

• 1,500 MVA or

• 20 percent 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 FRand SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three-phase short circuit MVA of the newly identified BES bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent 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. SER and 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 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner’s discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations 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 BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

3. DESCRIBE ANY CONSIDERATION OF THE USE OF IMPROVED INFORMATION TECHNOLOGY TO REDUCE THE BURDEN AND TECHNICAL OR LEGAL OBSTACLES TO REDUCING BURDEN

The use of current or improved technology is not covered in Reliability Standards and is therefore left to the discretion of each reporting entity. Commission staff estimates that nearly all the respondents are likely to make and keep related records in an electronic format. Each of the six Regional Entities has a well-established compliance portal for registered entities to electronically submit compliance information and reports. The compliance portals allow documents developed by the registered entities to be attached and uploaded to the Regional Entity's portal. Compliance data can also be submitted by filling out data forms on the portals. These portals are accessible through an internet browser password protected user interface.

4. DESCRIBE EFFORTS TO IDENTIFY DUPLICATION AND SHOW SPECIFICALLY WHY ANY SIMILAR INFORMATION ALREADY AVAILABLE CANNOT BE USED OR MODIFIED FOR USE FOR THE PURPOSE(S) DESCRIBED IN INSTRUCTION NO. 2

The Commission periodically reviews filing requirements concurrent with OMB review or as the Commission deems necessary to eliminate duplicative filing and to minimize the filing burden. Reliability Standards are developed by a collaborative process which requires industry participation. The Commission is unaware of any other source of information similar to the additional requirements.

5. METHODS USED TO MINIMIZE THE BURDEN IN COLLECTION OF INFORMATION INVOLVING SMALL ENTITIES

In general, small entities may reduce their burden by taking part in a joint registration organization or a coordinated functional registration. These options allow an entity to share its compliance burden with other entities.

Detailed information regarding these options is available in NERC's Rules of Procedure at sections 507 and 508.[8]

6. CONSEQUENCE TO FEDERAL PROGRAM IF COLLECTION WERE CONDUCTED LESS FREQUENTLY

8 Details of the current ERO Reliability Standard processes are available on the NERC website at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf#search=Appendix%203A .

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PRC Reliability Standards were established such that the declining frequency is arrested and recovered in accordance with NPCC performance requirements. The collection cannot be collected less frequently, as the proper targets need to be set in terms load tripping at the required frequency set points. Over time the amount of load on will change and if not reviewed it may result in missing targeted values and cause frequency decline that would trip generation leading to widespread uncontrolled outages.

The frequency this information is currently required is once per calendar year by the transmission owner and distribution provider to its planning coordinator and generator owners shall provide information upon request.

7. EXPLAIN ANY SPECIAL CIRCUMSTANCES RELATING TO THE INFORMATION COLLECTION

FERC-725G, has no special circumstances associated with the information collection.

8. DESCRIBE EFFORTS TO CONSULT OUTSIDE THE AGENCY: SUMMARIZE PUBLIC COMMENTS AND THE AGENCY'S RESPONSE

The Commission published a 60-day notice[9] in Docket No. RD23-4 in the Federal Register requesting comments. No comments were received in response to the 60-day Notice.

In addition, the Commission is publishing a 30-day Notice in the Federal Register[10].

9. EXPLAIN ANY PAYMENT OR GIFTS TO RESPONDENTS

The Commission does not make payments or provide gifts for respondents related to this collection.

10. DESCRIBE ANY ASSURANCE OF CONFIDENTIALITY PROVIDED TO RESPONDENTS

There are no specific assurances of confidentiality mentioned to respondents.

11. PROVIDE ADDITIONAL JUSTIFICATION FOR ANY QUESTIONS OF A SENSITIVE NATURE

This collection does not include any questions of a sensitive nature.

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9 88 FR 24787, April 24, 2023

10 88 FR 44119, July 11, 2023

12. ESTIMATED BURDEN OF COLLECTION OF INFORMATION

The estimates are based a combination on one-time (years 1 and 2) obligations to follow the revised Reliability Standard.

Proposed Reliability Standard PRC-002-4 (Disturbance Monitoring and Reporting Requirements) would advance the reliability of the BES by providing needed clarity regarding the application of the standard's requirements. First, proposed Reliability Standard PRC-002-4 would clarify requirements for notifications under the standard, including when Generator Owners and Transmission Owners must have data for an applicable transformer or transmission line. Second, the proposed Reliability Standard clarifies and promotes consistency in terminology used in the standard. Third, the proposed Reliability Standard brings the implementation timeframe for newly identified facilities into the standard. Last, the proposed Reliability Standard adds a criterion that defines what constitutes a substantial change in fault current levels that would require changing the locations for which sequence of events (SER) and fault recording (FR) data is recorded. The revisions and supporting rationale are discussed in further detail below.

Proposed Reliability Standard PRC-002-4, contains a number of revisions intended to clarify the standard, aid in its administration, and reduce ambiguities and unnecessary burdens. The proposed change to Attachment 1 Step 7 (referenced in the Appendix below) allows the possibility of significant change over time without a required change in data recording location. The Reliability Standard PRC-002-4 would provide necessary clarifications to the standard in the requirements R1, R3 and R5 and promotes consistency in terminology used in the standard. The new requirement R13 brings the implementation timeframe for newly identified facilities into the standard. These changes would clarify the extent of the required notifications and data collection requirements consistent with other provisions in the currently effective and approved versions of the PRC-002 standard.

> The number of respondents below is based on an estimate of the NERC compliance registry for balancing authority, transmission operator, generator operator, generator owner and reliability coordinator. The Commission based its paperwork burden estimates on the NERC compliance registry as of February 10, 2023. According to the registry, there are 325 transmission owners, 1,117 generator owners and 12 reliability coordinators. The estimates are based on the change in burden from the currently pending standard (i.e., PRC-002-3) to the standard approved in this Docket (i.e., PRC-002-4). The Commission based the burden estimates on staff experience, knowledge, and expertise.

Proposed Changes Due to Order in Docket No. RD23-4-000

Reliability Standard & Requirement	**Type[11] and Number of Entity** (1)	**Number of Annual Responses Per Entity** (2)	**Total Number of Responses** **(1) *(2) = (3)**	**Average Number of Burden Hours per Response[12]** **(4)**	**Total Burden Hours** **(3) *(4) = (5)**
FERC-725G					
PRC-002-4					
TO	325	1	325	16 hrs. $978.72	5,200 hrs. $318,084
GO	1,117	1	1,117	16 hrs. $978.72	17,872 hrs. $1,093,230.24
RC	12	1	12	8 hrs. $489.36	96 hrs. $5,872.32
Total for PRC-002 **One Time Estimate - Years 1 and 2**			**1,454**	40 hrs. $2,446.8	23,168 hrs. $1,417,186.56

The one-time burden of 23,168 hours that only applies for Year 1 and 2 will be averaged over three years (23,168 hours ÷ 3 = 7,722.667 (7,722.67 – rounded) hours/year over three years). The number of responses is also averaged over three years (1,454 responses ÷ 3 = 484.667 (485 - rounded) responses/year).

The responses and burden hours for Years 1-3 will total respectively as follows for Year 1 one-time burden:

Year 1: 485 responses; 7,722.67 hours

Year 2: 485 responses; 7,722.67 hours

Year 3: 485 responses; 7722.67 hours

11 TO=Transmission Owner, GO=Generator Owner and RC=Reliability Coordinator.

12 The estimated hourly cost (salary plus benefits) derived using the following formula: Burden Hours per Response * $/hour = Cost per Response. based on the Bureau of Labor Statistics (BLS), as of February 10, 2023, of an Electrical Engineer (17-2071) - $77.02, - and for Information and Record Clerks (43-4199) $42.35, The average hourly burden cost for this collection is [($77.02 + $42.35)/2 = $61.17)] rounded to $61.17 an hour.

The ongoing burden for PRC-002-4 remains unchanged

13. ESTIMATE OF THE TOTAL ANNUAL COST BURDEN TO RESPONDENTS

There is no start-up or other non-labor hour cost associated with this collection.

14. ESTIMATED ANNUALIZED COST TO FEDERAL GOVERNMENT

The estimate of the cost for 'analysis and processing of filings'[13] is based on salaries and benefits for professional and clerical support. This estimated cost represents staff analysis, decision-making, and review of any actual filings submitted in response to the information collection.

The Paperwork Reduction Act (PRA) Administrative Cost is the average annual FERC cost associated with preparing, issuing, and submitting materials necessary to comply with the PRA for rulemakings, orders, or any other vehicle used to create, modify, extend, or discontinue an information collection. It also includes the cost of publishing the necessary notices in the Federal Register.

FERC-725G	Number of Employees (FTEs)	Estimated Annual Federal Cost
Analysis and Processing of filings	0	$0
PRA Administrative Cost		$7,694
FERC Total		$7,694

15. REASONS FOR CHANGES IN BURDEN INCLUDING THE NEED FOR ANY INCREASE

The following table shows the total burden for the collection of information. The format, labels, and definitions of the table follow the ROCIS submission system's "Information Collection Request Summary of Burden" for the metadata.

FERC-725G	Total Request	Previously Approved	Change due to Adjustment in Estimate	Change Due to Agency Discretion
Annual Number of Responses	10,862	10,377	0	485
Annual Time Burden (Hr.)	721,995	714,272	0	7,723

13 The estimate uses the FERC's FY 2022 average annual salary plus benefits of one FERC FTE (full-time equivalent [$188,922 per year or $91.00 per hour]).

Annual Cost Burden ($)	0	0	0	0

For 725G (PRC Reliability Standards), the change (Increase in responses and burden hours) is due to agency discretion as we have updated the method to determine affected entities and their responses. Additionally, changes have occurred since last cycle in the number of NERC Registered Entities who have to follow these Reliability Standards.

Program Change
PRC-002-4 Increased by 485 responses and 7,723 burden hours for the One-time burden associated by the updated Reliability standard PRC-002-4 (previously PRC-002-3)

16. TIME SCHEDULE FOR PUBLICATION OF DATA

There are no data publications as part of this collection

17. DISPLAY OF EXPIRATION DATE

It is not appropriate to display the expiration date because the information is not collected on a preformatted form or is part of a Reliability Standard, which do not display OMB expiration dates. The collection associated with PRC-004 will be updated on Ferc.gov at https://www.ferc.gov/information-collections.

18. EXCEPTIONS TO THE CERTIFICATION STATEMENT

The Commission does not use statistical methods for this collection. Therefore, the Commission does not certify that the collection uses statistical methods.

APPENDIX A.

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data
(Requirement R1)
To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, 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 Bulk Electric System (BES) bus includes physical buses with
breakers 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.
Step 2. Reduce the list to those BES buses that have a maximum available calculated

three phase short circuit MVA of 1,500 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 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 percent.

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:

- 1,500 MVA or
- 20 percent 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 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

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