Individual or group. (51 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (19 Responses)
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Question 1 (43 Responses)
Question 1 Comments (51 Responses)
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Question 2 Comments (51 Responses)
Question 3 (41 Responses)
Question 3 Comments (51 Responses)

Group
Arizona Public Service Company
Janet Smith
Yes
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
Include the Quebec Interconnection in the Introduction Section 4 Applicability. Add to “4.1 The Responsible entity is:” 4.1.4 Quebec Interconnection - Planning Coordinator or Reliability Coordinator As an alternative, define a Responsible Entity for non-specified Interconnection areas. M12 – Remove “of”. Requirement R1, Part 1.2 requires from each Transmission Owner (TO) to notify other owners of BES Elements connected to identified BES buses. It is recommended to revise Part 1.2 to read that each TO provides the list of identified BES buses to their PC / RC who will notify those owners whose BES Elements require SER data and/or FR data. The PC / RC has more authority to maintain a master list of BES buses that require SER and FR data that can provide maximum wide-area coverage. This may avoid TO’s being challenged regarding BES bus selection. Requirement R11, Part 11.3. requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. If large data volumes are requested then TO / GO should have their say to the requestor about when they can provide the data in (.CSV) format. Some DME produces records from which SER data would need to be manually extracted, which is very time-consuming. However, the same SER data can be visually seen using COMTRADE viewing software. The standard should not make a file format (such as .CSV) a mandatory requirement. Additionally, Part 11.3 asks to combine SER data from multiple DME devices and from multiple stations. This could be very time consuming and subject to errors.
Individual
Joe O'Brien on behalf of Chirag Patel
NIPSCO

Yes
R3 , GSU transformers are excluded based on the drafting team’s assumption that a fault on the transmission system would be captured by FR data on the Transmission System equipment (line, bus terminals) which is an accurate assumption except for faults on the bus itself. In certain configurations where multiple GSU units terminate into a single Transmission Bus, it is uncertain if this could indeed be calculated as stated by deciphering the contribution from various units. As stated in the current draft of PRC-002-2 Pg 39 of 46 top of page, current calculations would not be required from the GSU terminals of each generator since they can be readily calculated if needed, which is not an accurate statement in all configurations. This leaves what could be a substantial gap for bus faults or for configurations where multiple units of different sizes terminate on separate terminals of the transmission bus. Example would be a large Transmission Substation with a breaker and half configuration with 4 GSU units all terminating on separate terminals into the transmission bus. These units could be of different size and fuel source (Coal units, gas turbines, etc) all terminating to the same transmission bus leaving a substantial gap in FR recording data since the only thing that will be captured is the aggregate of the generation through calculation for external faults, and only simulated data for bus faults. Generators are typically the most significant contributor to transient and sub-transient local fault current at or near larger generation facilities, and also the most susceptible cause of cascading which may result from instability following a system disturbance. Therefore, this requirement would not provide the required data to decipher problem areas on specific generators that may have truly been the root cause without extensive simulation of data using, what would then be, calculated empirical data, not real captured data. This exclusion only appears beneficial for external close in faults and configurations where either a single GSU is connected to the transmission system or a single collector bus with an aggregate GSU source from many of the same units are connected to a Transmission Bus. For the purposes of the standard, exclusions should not be granted to generation terminals since it would result in a discriminatory practice. All significant sources of fault current on an applicable BES Transmission Bus should be deemed equally important for capturing FR data and the only exclusions should be to terminals or elements which only provide load.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
Within the Rationale for Requirement R10, it is unclear which device the drafting team intends to be synchronized to within +/- 2 milliseconds of UTC. Although the last paragraph of the Rationale for R10 states that the “accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment”, the following sentence states that “the equipment used to measure the electrical quantities must be synchronized to +/-2 ms accuracy”. This creates confusion in terms of whether the accuracy requirement applies to the clock used for synchronizing the monitoring equipment, to the monitoring equipment itself, or to both. Recommend additional clarification be included within the Rationale for R10 or else to R10.2 to prevent further confusion.
Yes
As currently written, LES is having difficulty following Attachment 1 due to the confusing references. At a minimum, recommend clarification be added as to what “list” each step in the attachment is referring to, considering that the “list” may change throughout the steps. For example, in Step 3, does the “list” in the second sentence refer to the list created in the first sentence, or is it referring to the “list” created in Step 2? Or should the second sentence in Step 3 be moved to Step 2? Without additional clarification, it is difficult for an entity to determine how to proceed through the steps in the attachment, especially Step 7.
Individual
Amy Casuscelli
Xcel Energy

Yes
In response to Xcel Energy’s comment in the previous ballot, the drafting team states that changes were made in Step 7 and 8 to recognize that requiring close busses have date recording equipment would not provide significant value. However, a review of these steps in the redline document does not show that changes were made to address this issue. The drafting team did add language in the Rationale box under Requirement 3 addressing busses serving only generators but it is not clear how this rationale statement is made part of the requirements. Because of the perceived conflict in the rationale compared to the requirement, Xcel Energy is voting negative on the standard. We believe that the rationale statement is correct but the change has not been implemented in the requirement and associated calculation. Please correct this oversight. Thank you for your effort on this issue.
Group
Seattle City Light
Paul Haase
Yes
Seattle City Light does not support this Standard as structured or as written. We believe siting of monitoring equipment should be coordinated at a higher (regional or sub-regional) level to promote the most cost-effective installations. We do not believe the proposed level of technical detail (which changes constantly as technologies improve and change) is appropriate to a federal Standard (which is very difficult and slow to update and change). Finally, if a Standard something like the proposed approach is necessary, we find the 1500 MVA fault duty values to be low by a factor of 3 or 4, if not perhaps by a factor of 10.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Yes
Individual
David Jendras
Ameren
Yes
We believe that Requirement R5 as written would require the addition of about a dozen additional PMUs to our system. For us this number would be much more manageable than the number called for in earlier drafts of this standard. Because this draft targets monitoring generators of significant size, disturbance monitors can potentially generate disturbance data useful in refining dynamic model representations for this equipment over time.
Yes
Based on our experience it would be difficult to keep communications network delays within the +/-2 millisecond window. In our opinion, a reasonable approach would be to limit this requirement to the synchronizing clock equipment as shown in the modified draft standard, which would be feasible and sufficient.
Yes
To help assure the ability to meet the 90-day time limit for Requirement R12, we believe that it may be necessary to have at least one spare of each model of PMU installed on the system on hand for use in replacing a failed unit in a timely manner.
Individual
David Thorne

Pepco Holdings Inc
Yes
Yes
No
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
No
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration L.P. (ICLP) agrees with the extensive and consistent negative response from a number of respondents to the previous posting regarding DDR. We (and they) believe that R5 will unnecessarily over-drive the deployment of phase measurement units (PMUs). PMUs are a fast improving technology and the DDR owners will quickly find that their equipment is obsolescent. We can agree that PMUs must be deployed in critical areas regardless, but do not see the same sense of urgency for locations of lesser BES importance. Specifically as a GO, ICLP agrees with the criteria developed in PRC-023 and CIP-002 to establish critical generation facilities. In our view, this would be those whose aggregate output exceeds 1500 MVA and attach to the BES at 200 kV or more. (Of course, there must be special consideration for facilities that are part of a SOL/IROL, but those locations are already captured in R5.) After the industry gains familiarity with PMU technology, further integration at lower capacities and voltages may be considered. By then, there will be far more exciting and useful options available – and will no doubt prove to be more useful to investigators trying to consolidate data related to a wide-area outage.
Yes
Individual
Mark Wilson
Independent Electricity System Operator
Yes
We agree with the changes made to the BES Elements requiring data listed in R5, but have concerns over the other changes to R5 (and R1). Please see our comments under Q3.
Yes
Yes
We generally agree with all the proposed changes. However, the addition of the phrase “and implement the reevaluated list of BES buses as per the Implementation Plan” to Part 1.3 and the phrase “and implement the reevaluated list of BES Elements as per the Implementation Plan” to Part 5.4 is unnecessary which makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the

concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot.
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12. Our concern on this matter has led, in part, to our decision to vote negative on the standard. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. Our concern on this matter has led, in part, to our decision to vote negative on the standard. As stated in our previous comments, AEP recommends modifying R3 so that only three of the four currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents. The drafting team responded by saying “The Rationale Box for Requirement R3 explains the need for the three phase currents and the residual or neutral current”, however it is not necessary to monitor all these quantities to provide the data mandated by R3. It is clear from the rationale section for R3 that GSU transformers are excluded from the requirement. However, R3 states “Each TO *and GO* shall have FR data…for the BES Elements it owns connected to the BES buses…”. The requirement should be revised to align with the exclusion provided stated in the rationale section. R12: We see no reliability benefit in sending all CAP’s to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. R2: We believe that it is clear that the TO/GO must have SER data for circuit breaker position as it related to the following BES elements connected to a BES bus; BES Transmission Lines, BES Transformers and BES Generator feeds. Does this Requirement also apply to circuit breakers/circuit switchers that serve BES shunt capacitors/reactors?
Individual
John Pearson/Matt Goldberg
ISO New England
No
By definition, SOLs do not impact other areas and, for that reason, it would be more appropriate to leave the determination regarding monitoring of SOLs up to the Responsible Entity. Accordingly, Requirement 5.1.2 should be deleted. However, if Requirement 5.1.2 is not deleted, then the words “Any one” in Requirement 5.1.2 should be replaced with the words “One or more.” This will make it clear that the Responsible Entity is required to select one (or more) BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL) and will also make Requirement 5.1.2 consistent with Requirement 5.1.4, which already uses the words “One or more.” In Requirement 5.1.3, the word “circuit” should be replaced with the word “interconnection” or the word “facility” to ensure that back-to-back HVDC is monitored; these types of interconnections are being planned for New England and the word “circuit” may create confusion about monitoring them. Also, to make Requirement 5.1.3 clearer, the words “…for which the Responsible Entity is responsible” should be added at the end of the sentence. The words “Any one” should also be replaced with the words “One or more” in Requirement 5.1.5. Again, this will make it clear that the Responsible Entity is required to select one (or more) BES Element within a major voltage sensitive area as defined by an area with an in-service UVLS program, and will make the requirement consistent with Requirement 5.1.4.
Yes
Yes

The triggers described in the first two bullets of Requirement 8.2 should be clarified to include the duration that the Standard Drafting Team based them on. Otherwise, the data produced may be inconsistent across interconnections and may be subject to different interpretations. Requirement 11.3 should be deleted because providing the data in formats other than ASCII Comma Separated Value (.CSV) should be allowed. In other words, the requirement should not prescribe a data format.
Individual
Manon Paquet
Hydro-Quebec Production
Yes
Yes
No
Individual
Chris Scanlon
Exelon Companies
No
Regional DME criteria in RF was 1000 MVA, Exelon thinks the threshold in R5 should be raised to the 1000 MVA per the RF Criteria.
Requirement R7.1: For clarity consider replacing the first comma with “or” to read “One phase-to-neutral or phase-to-phase or positive sequence voltage……” R7.2: Similar comment - for clarity, consider rewording to replace the commas with “or” to read “The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7.1 or phase current(s) for any phase-to-phase voltages or positive sequence current.” R9.3 requires an output recording rate of at least 30 times per second while the existing NPCC and RFC-CRITERIA-PRC-002-01 requires a recording rate of 6 times per second. Some of the equipment in question was installed in the last several years to meet the RF stadnard/criteria. To meet this new requirement legacy devices will need to be either upgraded or replaced because the higher recording rate will mean they cannot hold a continuous 10 day record. Relaxing the recording output rate to the existing 6 times per second would be sufficient to allow these devices to be compliant with the requirement. The implementation plan for PRC-002-2 includes the following installation requirement for newly-added buses from the re-evaluation process: “Entities shall be 100 percent compliant with a re-evaluated assessed list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated of the list.” The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage / maintenance cycles . Modifying outage cycles with the time necessary to specify and acquire new equipment will be disruptive. In place of a prescriptive cycle requirement, we propose the requirement be changed to say, Entities shall submit a plan to be 100% compliant with a re-evaluated list from requirements R1 and R5 within 180 days following notification by the TO/Responsible Entity. This plan should include expected completion date(s) justified by outage constraints, equipment lead times and availability. R12 and/or M12 should be modified. We will be using microprocessor relays that also provide protection for SER, FR, and DDR functions. Microprocessor relays that provide protection functions are not allowed to be out of service following a failure for anywhere near 90 days. In addition, we have these relays on all 200kV and above lines. Thus, the failure of one device is not too important from a DME standpoint. Given all this, this requirement is unnecessary for an entity using microprocessor relays as described. We propose that M12 states that protective relaying also used as DME is excluded from this requirement since it is inherent that it will be fixed in less than 90 days. Keeping data to show that relay failures were repaired in less than 90 days is an unnecessary administratve burden and does not contribute to reliable operations. The standard should recognize the varying technologies are used to perform this function and not create administrative burdens. An alternative might be to change the measure to state that if an event occurs that requires RRO or NERC investigation sufficient data was made available to NERC or the RRO to support the event investigation. This will eliminate the need to keep records proving that equipment was fixed in a timely manner.

Individual
John Allen
City Utilities of Springfield, Missouri
No
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
No
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
Yes
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group and the following additional suggestions: Regarding R1 and Attachment 1: We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. All of the BES buses on our system have fault MVA above the 1500 MVA threshold and no reduction to the number of buses on our list occurs by application of the steps outlined in Attachment 1. Given the size of our utility, it seems odd to us that all of our buses are considered “key” to the BES. Regarding R3: We continue to believe it is not necessary to be able to determine the electrical quantities associated with every element connected to a bus for a fault on one element of the bus. Rather, we believe that if devices are present to capture sufficient data necessary to determine the required quantities associated with the “faulted” element, that is sufficient for fault analysis. We believe it is sufficient for an entity to be able to determine fault location, fault type, cause of relay operation and the currents and voltages required by this proposed Standard associated with the faulted element for the purposes of Fault Recording. This seems to meet the intent voiced in the “Rationale for R3”. Please clarify the purpose of requiring electrical quantities be determined for all elements connected to a bus for a fault on any element of that bus if the required quantities associated with the faulted element can be determined. Also, it seems to us that comments regarding determining correct operations of the protection system within the proposed Standard and guidelines document are out of scope for this Standard and are already covered in other NERC Standards, PRC-004 specifically. Regarding R4: We appreciate the SDT revising the total record length in the first bullet under R4.1 from at least 32 cycles to at least 30 cycles. Regarding R10: We appreciate the SDT’s clarification that the time synchronization pertains to the device clock.
Group
ACES Standards Collaborators
Brian Van Gheem
No
We appreciate the DMSDT’s decision to incorporate more explanation in the rationales of this standard based on its extensive outreach to event analysis subject matter experts. We feel that the DMSDT has taken steps to answer some of the concerns regarding the requirements that seek to find “why” an event occurred. However, we continue to disagree that the standard addresses the “what” of data collection and not the “how” the data is collected. How is an entity going to provide data if it does not have the equipment present to collect it? The fundamental principles of this standard seem flawed when the purpose of this standard is to have “adequate data available to facilitate analysis of BES Disturbances.” We feel NERC can communicate the intent of collecting data for the purposes of explaining why an event occurred through a Reliability Guideline instead of an enforceable standard. NERC already has enforceable standards on reporting events, monitoring system conditions, and identifying entity-to-entity data specifications. The data collected and available through these existing standards are through “proactive” devices and applications, which entities then generally archive for historical and training purposes. We believe sufficient data is already available, as evident with the data available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, “PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP).” The resulting report identified no additional standards because of this event. By continuing to pursue an

enforceable standard to address outdated recommendations from the 2003 Blackout in the Northeast does not seem cost effective for both industry and NERC. A Reliability Guideline will not deter industry from installing additional or maintaining existing event recording devices. However, it gives industry an opportunity to balance the risk of not installing or maintaining such devices with pursing advancements in technologies with the more “proactive” and “preventable” devices and initiatives.
No
We feel that NERC can communicate technical specifications for data collection explaining why an event occurred through a Reliability Guideline. As stated on the NERC web site, “reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability.” We feel NERC and industry jointly pursuing a Reliability Guideline on this topic collaboratively would be better use of time and resources.
Yes
(1) When compared to other enforceable standards, the number of requirements identified in this standard is greater than the number of requirements currently enforceable for standards related to event reporting and entity-to-entity data specifications. We continue to believe that many of these requirements are unnecessary and fall under Paragraph 81 Criteria B. However, if the DMSDT feels that such information is “essential to expeditious and efficient data analysis,” we believe these technical specifications could be included in a technical guideline or Compliance Section attached to this standard. Requirements R4 and R9 regarding data sampling and requirement R10 regarding time synchronization are just three of the numerous specifications listed in this standard. Requirement R11 identifies the data format and nomenclature expected for entities to follow. Even the current requirements associated with the Disturbance Control Standard, NERC Standard BAL-002-1, do not identify the data format as a requirement. Moreover, the individual parts of requirement R11 cite various IEEE standards and specifications, references the DMSDT could identify as footnotes. Many other SDTs, such as the one that developed NERC Standard PRC-023-2, relocated their technical information to other appropriate areas or documents. Likewise, requirement R8 identifies system conditions that are necessary to trigger the initiation of data recording if continuous data recording is unavailable. We believe the DMSDT should move these technical specifications to an appendix of the standard and not identify them as enforceable requirements. (2) We concur with the DMSDT that the term “BES buses” provides confusion. We believe requirements R1.1 and R1.3 should be rewritten to “BES Elements connected to a BES bus” to alleviate any further confusion. (3) We believe the term “and/or” listed in Requirement R1.2 could provide confusion. We recommend change the requirement to read, “Notify, within 90-calendar days, other owners of BES buses identified within R1.1 that require SER data and FR data.” (4) We believe the DMSDT should remove references to the Implementation Plan, as embedded directly within the requirement text, and incorporated this information into an “Effective Date” entry listed under the Introduction (Section A) of this standard. Such references include R1.3 and R5.4. (5) We believe the DMSDT should remove the reference to “local time offset” in Requirement R10.1. Its reference to the time listed in SER and FR data and their synchronization to Coordinated Universal Time (UTC) is an unnecessary addition to the text of this requirement. (6) Requirement R11 identifies that entities are required to provide all SER and FR data, upon request, to the Regional Entity and NERC. NERC already defines this mechanism in Section 1600 of the NERC Rules of Procedures. We suggest the DMSDT remove all references to the Regional Entity and NERC from this requirement. (7) Requirement R12 states that an entity should first submit a Corrective Action Plan (CAP) to its Regional Entity and then implement the plan. We recommend the DMSDT follow a similar approach taken in NERC Standard PRC-004-3, where the entity is first required to develop a CAP and then required to implement and provide updates until the plan is completed. Both industry and NERC have already reviewed this language and the standard is currently on file with FERC. (8) The term “Responsible Entity” is already a defined term in Appendix 2 of the NERC Rules of Procedures. We recommend the DMSDT revise all references to Responsible Entity within this standard accordingly. (9) We continue to disagree with the DMSDT that this standard addresses the “what” of data collected and not “how” the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. The DMSDT continues to rebut our previously submitted comments with references to the 2003 Blackout in the Northeast. However, it

was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, “PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP).” Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability. (10) Thank you for the opportunity to comment.
Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
Yes
Luminant is specifically concerned about the administrative requirements in the standard related to reporting formats. Luminant does not disagree with the desire or benefit of standardized reporting, however, we believe specific data and reporting formats do not belong in the standard requirements. The ERO already has the authority to request data and reports in specific forms or formats. (1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. We reiterate our concern that these items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting. The requesting agency has the right to ask for data in any prescribed format they desire, but this should not be identified in the standard. (3) Requirement R11, subsection 11.4 specifically references “IEEE C37.111-2013”. We reiterate our previously submitted comment on the version specification. The SDT response focused on conversion software. Some older DFRs that effectively capture the needed data may not meet this requirement for the “2013”. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This 2013 mandate is administrative in nature and does not contributed to a results based standard nor improve BES reliability. This version requirement should be revised to allow for any versions that the entity has access to that supports the recording and report requirements.
Group
Dominion
Mike Garton
No
See comments in Question #3.
No
See comments in Question #3.
Yes
Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Reliability Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. Project 2007-11 began in March 2007 with the objective to develop a continent-wide Disturbance Monitoring (DM) Reliability Standard. One Regional Entity (NPCC) developed a DM Regional Reliability Standard (FERC approved) in absence of a continent-

wide standard. Dominion does not support this Reliability Standard and recommends that the SDT consider the following: 1. Is a continent-wide DM Reliability Standard necessary? With the exception of NPCC, no other Regional Entity has a Regional Reliability Standard for DM. Perhaps existing regional guidance/practices employed since 2007 are sufficient. There has been many new installations of DM equipment since the Version 0 fill in the blank standard was remanded back to NERC. Perhaps a suitable alternative to a standard would be for NERC to issue guidance similar to guidance that was issued for cold weather preparedness in lieu of a standard. 2. Duplicity and/or differences between Regional Reliability Standard and continent-wide Reliability Standard. Specifically: Dominion remains concerned that PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2014, NPCC applicable entities are three years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Once approved, NPCC applicable entities must comply with both PRC-002-2 and PRC-002-NPCC-01, requiring those entities to review and determine the more stringent requirements between the regional and continent-wide standards. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01). 3. Equipment installation may be necessary to obtain the data specified in the Reliability Standard. Considering the criteria, some merchant generators, but not all, will incur costs that are not recoverable to install the equipment. This results in an unfair competitive advantage for some market participants. 4. Please consider the following items for consistency: M1 needs to be updated to include Parts 1.1, 1.2, and 1.3, similar to how M4 and M5 included the Parts. R11.1 should be reworded to include the word “consecutive” to read “period of 10 consecutive calendar days” and change test from “the data was recorded” to “the data was requested.”
Individual
Anthony Jablonski
RelliabilityFirst
No
ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the “fill in the blank” aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R5, Part 5.3 - Requirement R5, Part 5.3 requires notification within 90- calendar days of completion of Part 5.1, but then goes on to state “when requested”. ReliabilityFirst questions whether the intent is “within 90-calendar days” or “when requested”. ReliabilityFirst believes the SDT should choose one or the other. 2. Requirement R5, Part 5.4 - Requirement R5, Part 5.4 references an “Implementation Plan” and it is unclear to ReliabilityFirst how this will be enforced. The Implementation Plan only speaks to the initial identification of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements that reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 5.4.
Yes
ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the “fill in the blank” aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Part 1.3 - Requirement R1, Part 1.3 references an “Implementation Plan” and it is unclear to ReliabilityFirst how this will be enforced. The posted PRC-00202 Implementation Plan only speaks to the initial identification of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements which reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 1.3.
Individual
Jamison Cawley

Nebraska Public Power District
No
R5 5.2 states "5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand." Please explain how "Ensure a minimum DDR coverage" relates to the implementation plan where 100% compliance is required within 6 months of approvals. What is R5.2 acceptable evidence after 6 months? Is this just an identification requirement that the planning coordinator must provide in this 6 month time frame? This question arises because "Ensure" is used instead of "Identify". R5 question: For example, a utility has two DDRs on its system because it has two generating resources greater than 500 MVA at two separate locations. If this utility also has 3,030 MW peak demand will the two DDRs on its system satisfy R5.2? In addition to these comments, we also support the comments provided by SPP.
No
We support the comments provided by SPP.
R11 requires "Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded." It appears a chattering contact could easily fill up an SER or FR device in a matter of minutes or less if it occurs near an event. It is difficult to control or address these issues but they could be a serious impact to the 10 calendar day requirement. Is there a way to minimize this requirement such that event triggers or SERs don't need to be decreased to help ensure data has less chance of being overwritten? Some microprocessor relays only hold 12 event records so this is more difficult to guarantee data is available this long. In addition it is possible to have more than 12 operations within 10 days during stormy periods. It would seem this case would not allow the data to be available in a relay for the required time. This requirement could force utilities to eliminate many older microprocessor relays on the system that have limited programming and memory capability where the risk for non-compliance could be too great. If this happens then the assertion that many of devices are already on the system that meet the recording requirements is not a generally true statement. Consider removal of this 11.1 requirement since this capability is not entirely under the control of the owner. M1 question: Do we need to just show we sent a notification within 90 days to other owners of BES elements for an identified bus or also show a response? Just showing we sent the notification in good faith is preferred. R12 question: The implementation plan states we have 9 months after approval to be 100% compliant for R12. Does this mean we need to be compliant for R12 with elements as they become compliant in R2, 3, 4, 6, 7, 8, 9, 10 and 11 over the implementation time frame? For example, since it could be 4 years and only 50% of elements and their recording capabilities will be compliant how is requirement R12 applied to locations not yet compliant? R4 states: "Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent." Is it possible to allow additional "OR" statements for 4.3.2? Many relays used for FR will use the phase impedance zone reaches to trigger records. This can clearly define the reach for data to be triggered where defining an under voltage or overcurrent may be more difficult to control the reach. There is some concern with overwriting data in the relays with settings that are less intuitive for controlling how often a device may trigger. We strongly recommend allowing phase distance reaches as trigger points. In past comments it may have appeared to be suggested as overcurrent or distance be included but what was meant was to have both as part of an OR statement. Suggestion: Phase under voltage or overcurrent or distance reach. R12 states "Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it." Should the RE or regional entity be listed in the Applicability section? For some registered entities the Planning Coordinator and the Regional Entity may not be the same. In addition to these comments, we also support the comments submitted by SPP.
Individual
Gul Khan
Oncor Electric Delivery LLC
No
In the rationale for R5 it states "For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data." We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an

interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below: “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.”
Yes
Yes
We recommend the following language from the R7 to be used in R3 “Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.” As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added: “If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR.” Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: “The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable”
Individual
Gul Khan
Oncor Electric Delivery LLC
No
In the rationale for R5 it states “For an interconnection between two TO’s, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.” We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below: “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.”
Yes
Yes
We recommend the following language from the R7 to be used in R3 “Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.” As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added: “If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR.” Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: “The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable”
Individual
Jonathan Meyer
Idaho Power
Yes

Yes
No
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
1) Requirement R12: Texas Reliability Entity, Inc. (Texas RE) reiterates the concern raised during the previous ballot period that the Regional Entity is the appropriate entity to receive a TO or GO's Corrective Action Plan (CAP) as written in this requirement. Based on the language in the "Rationale for Functional Entities," it appears that either the Planning Coordinator (PC) or the Reliability Coordinator (RC) should be the recipient of the CAP. The Rationale for Functional Entities states that the "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 BES Elements for which dynamic Disturbance recording (DDR) data is required." Since the PC or RC is responsible for determining which BES Element data is needed, then they arguably need to know when there is a failure of the recording capability for that data and what the CAP is to restore the recording capability. The PC or the RC are in a better position to evaluate whether a CAP has been implemented. Therefore, submitting the CAP to the PC or RC is more appropriate than submitting the CAP to the Regional Entity as it will likely enhance reliability. Texas RE recommends the SDT change the second bullet under Requirement R12 from the "Regional Entity" to the "Responsible Entity." 2) Requirement R1 VSLs: The language within the first "OR" of the Lower VSL states the TO was late by 30 calendar days or less for Parts R1.1 and 1.3. Texas RE has two concerns regarding the language: A) Texas RE is not clear on what the VSL criteria of 30, 60, 90 or more than 90 calendar days is measuring against. Would the SDT please explain what the TO would be late for since Requirement R1.1 has no time criteria? B) Texas RE requests the SDT consider whether the VSLs for re-evaluating all BES buses at least once every five calendar years for Part R1.3 is appropriate. For an evaluation that is deemed sufficient to be performed at a frequency of every five years, it would seem that being late by 30, 60, 90 or 90-plus days might not be the correct timeframe for assessing the severity of a violation. Texas RE suggests assigning criteria on quarters. So that a Lower VSL would be late by one quarter, Moderate VSL would be late by two quarters, High VSL would be late by three quarters and Severe VSL would be late by four quarters based on the previous evaluation date.
Group
Peak Reliability
Jared Shakespeare
No
The Requirement should be revised to include "in its area" to allow for multiple Responsible entities in an Interconnection. R5.2: "DDR coverage" should be changed to "DDR coverage identification." It is not reasonable that the Responsible Entity ensure DDRs are placed into service, rather that they are identified and notification sent to owners. R5.3: Currently in the Western Interconnection, there is no established mechanism to determine BES Element owners. Also, the phrase "require DDR data when requested" is confusing. Is the Responsible Entity only required to notify owners that DDR is required and data may be requested in the future? Peak recommends rewording the Requirement to better reflect the intent. R5.4: "and implement the reevaluated list of BES Elements as per the Implementation Plan" should be deleted because it's not the responsibility of the Responsible Entity to implement, only to identify and notify. Deleting that phrase will make it consistent with R5.3.
No

"that meet the following" should be "to meet the following". Using "that" implies that the data that doesn't meet those requirements isn't applicable. We assume the SDT meant to convert all data to meet the time-synchronization requirements.
Yes
R12: "to the Regional Entity" should be "to the Regional Entity and to the Responsible Entity". This will ensure the Responsible Entity is aware of data outages.
Group
PPL NERC Registered Affiliates
Stephen J. Berger
Yes
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5, but not that GOs are the parties that should collect this information (R7). There has been much discussion between the North American Generator Forum (NAGF) and the Disturbance Monitoring Standard Development Team (DMSDT) regarding assignment of responsibility for monitoring disturbances, and we believe GOs should be excluded for the following reasons: - TOs interpret and use DME data; GOs do not. - TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. - DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side. - Disturbances are more likely to originate in the transmission system than in generation plants (as was the case for the Northeast blackout of 2003), and responsibility should rest with the party causing the need for monitoring. We understand that duplication of equipment is not mandated – a GO could contract with it's TO to supply DDR data. It may not be possible to negotiate such agreements, however, due to the impracticality of transferring compliance responsibilities and the GO risk exposure if TOs commit to sharing data but not to achieving PRC-002-2 compliance. The NAGF attempted to find common ground with the DMSDT by recommending that the standard should at least state that TOs are responsible for providing DDR data if they already have such equipment at plants, but this request was evidently rejected, and R7 as presently written is therefore likely to lead to widespread wasteful duplication of equipment and effort. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over recordings (GOs) for further analysis. The entire subject of DME should be a TO matter and applicable to the TO's DME equipment that is already installed.
Group
Associated Electric Cooperative, Inc.
Phil Hart
Yes
1. AECI agrees with the SDT's list of elements. 2. Would the SDT provide some further clarification on exactly what "DDR coverage" would be considered? Further, some unofficial guidance was given to the effect that, neighboring entities DDR systems could be used for evidence if all required DDR data is collected by that unit. 5.3 goes on to state that notification to these entities is required, however provision of that data by the entity is not. Does the SDT believe the current language has sufficient measures to facilitate this "sharing" of DDR equipment?
Yes
No

Group
Duke Energy
Michael Lowman
Yes
Yes
No
Individual
Bill Temple
Northeast Utilities
No
The minimum requirements in R5.1 should be eliminated because they are overly inclusive. The Requirement should just be limited to R5.2 requirements. NU's Responsible Entity is on record as having adequate DDR monitoring for the region as such this requirement would add 20 DDR's to the region 10 in NU's footprint. The approximate cost to the region would be about $3 million with no benefit to system reliability.
No
NU does not support the revision to R10. NU has researched and found that there can be as much as 10 ms difference between the clock and time stamp. Recommend the SDT R10 should be returned to the previous draft
No
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
Yes
TAL believe that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Individual
Scott Langston
City of Tallahassee
Yes
Yes
TAL believes that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Individual

Andrew Pusztai
American Transmission Company LLC
Yes
ATC recommends updating the verbiage of Requirement 5.1.4 to read, “One or more BES Elements that are part of an Operating or Planning Interconnection Reliability Operating Limit,” for clarification.
Yes
Yes
ATC recommends correcting the typographical error in Requirement 11.2. The text should read, “Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.”
Group
Florida Municipal Power Agency
Carol Chinn
No
It needs to be clear that 5.1.2 and 5.1.4 are dealing with SOLs and IROLs established for the Planning Horizon by the Planning Coordinator or Transmission Planner. Reliability Coordinator SOL methodologies are dealing with a shorter timeframe, in the Operating Horizon, within which it may not be possible to engineer, procure, and install the equipment necessary to meet the requirement, especially as the results of the application of the SOL methodologies may be changing as system conditions change. Also, the revised RSAW does not give any guidance to the auditor as to which set of SOLs and IROLs (Planning Horizon or Operating Horizon) to be looking at. There are some PCs that only have one BES bus, so 5.2 as written would require them to have a disproportionately higher percentage of DDR coverage than larger entities. FMPA suggests 5.2.1 be deleted in order to achieve a fairer tier to required DDR coverage. At the very least, 5.2.1 should be changed to “One BES Element; or” which we believe is what the drafting team intended. Taken together, 5.2.1 and 5.2.2 means at least two BES Elements need DDR coverage. Note that the clean version has 5.2.1 written as “One BES Element; and” while the redline version has it written as “One BES Element”
No
The requirement language still speaks to synchronizing the data even though the rationale states it should be the equipment and not the data that is mandated. There is also a grammar problem with the addition of the phrase “that meet the following:”. We believe it was intended that the equipment meet the 10.1 and 10.2 criteria and not the data or the BES Elements as it is worded. FMPA suggests the following language: “Each Transmission Owner and Generator Owner shall time synchronize all SER and FR equipment for the BES buses identified in Requirement R1 and all DDR equipment for the BES Elements identified in Requirement R5 to meet the following:”
FMPA believes the standard, as written, places an onerous burden upon small Transmission Owners and Planning Coordinators that may only have one or two BES buses. The language and methodology effectively guarantee that such small entities must install equipment and report data under the standard. In R1, FMPA believes the Responsible Entity should be the one applying the methodology in Attachment 1 instead of the Transmission Owner. It is more appropriate from a Functional Model perspective to have the Planning Coordinator, for example, obligate the Generator Owner to the requirements that follow. Also, the Responsible Entity has the wide area view that will allow for more dispersed equipment, and lessen the potential for duplicative coverage. The Responsible Entity may need to use data from the Transmission Owners in its area, but once it has the data the formula in Attachment 1 can be followed. There are logical problems, as well as, issues with the inherent tiering between smaller entities and larger entities with Attachment 1. In Step 2, 1500 MVA is too low for small entities with few busses because they are either in remote locations and pose little risk of causing wide-area events or are located near facilities of a large neighbor that drive up the short circuit MVA level of the buses they own. In the latter case, the neighboring facilities would be better candidates for SER and FR data and there would be no value in having additional data from the nearby facilities just because there is a different responsible entity. The main issue hinges upon the fact that the 1500 MVA threshold works well as an initial tool for evaluating large systems with many buses but does not work well as a singular and final compliance

threshold (which is what it becomes for small entities). FMPA suggests raising the 1500 MVA criteria in Step 2 to at least 3000 MVA (or higher) for entities with 11 buses or fewer in their system. Step 3, as worded, is confusing because it causes a list of 11 buses to be determined and then causes steps to be skipped if there are 11 or fewer buses, which will always be the case. FMPA suggests replacing in Step 2 the phrase "If there are no buses on the resulting list, proceed to Step 7." with "If the list has 11 or fewer buses, proceed to Step 7." and deleting the same phrase from Step 3. Zero is fewer than 11, so we believe this results in what the drafting team intended. In Step 7, the reference to Step 3 should be a reference to Step 2. The word "the" should be deleted in the phrase "at least the 10 percent". FMPA appreciates the SDT comment responses. Unfortunately, these responses do not mitigate the concerns raised in general about the need for the standard versus a guideline. Plus not all of our comments were addressed. Our prior concerns still remain in addition to some additional concerns. SDT Response 1:"The Standard Drafting Team realizes that improvements have been made to Disturbance Monitoring technology since the 2003 Northeast Blackout. That does not guarantee universal implementation, thus necessitating the need for the standard." --While the SDT may "realize" that improvements have been made over the last decade, the SDT has not provided a risk assessment to quantify the need for a standard versus a guideline recognizing the technology advances and PMU equipment installed through the DOE Smart Grid program over the last decade. A risk assessment would be a beneficial exercise to identify gaps first, as opposed to taking a broad brush approach. It would also provide for more focused impact and faster results. SDT Response 2: "PRC-002-2 addresses "what" data is recorded, not "how" the data is recorded. This approach eliminates the complications that might arise from the technological advances being made to record the data" --The fact that this standard is requiring data vs equipment does not mitigate the fact that equipment will need to be installed which raises a cost recovery concern that needs to be addressed. SDT Response 3: "The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better Real-time system management (Real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events." --Guiding operators goes beyond the scope of the standard for a number of reasons, but most importantly due to the fact the Time Horizon is "Long Term Planning" and not "Real-time Operations". This raises another concern, which is with regard to the purpose of the standard which now states: "To have adequate data available to facilitate ("event" has been removed) analysis of Bulk Electric System (BES) Disturbances (now upper case)". By removing "event" and capitalizing "Disturbance", which is very broadly defined in the NERC Glossary, this broadens the scope of the purpose of this standard. In R11, there is no defined need for which a Responsible Entity, Regional Entity or NERC can request all SER, FR and DDR data. FMPA believes criteria for making a data request is needed.
Individual
Karen Webb
City of Tallahassee
No
TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
No
TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
No
Group

Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
Yes
Yes
1. It is believed that direct P & Q measurements are not required and the DDR can calculate these from measured voltages and currents- We recommend that the SDT clarify this in the Requirement or Rational box. 2. We would like the SDT to consider an alternative approach to this subject. It would be to have to have NERC or the RE's develop a map of the BES with the locations of current DME, then determine the areas where additional DME is needed to analyze a system event? This would eliminate the shotgun approach of basing the install on MW values, and insure that the program is cost effective. Some of the Reliability Entities may already have enough recording equipment. For example RFC may have a map of their footprint from their 2010 data request.
Individual
John Brockhan
CenterPoint Energy Houston Electric
Yes
Yes
Yes
As stated in comments previously submitted regarding requirement R10 in conjunction with requirement R2, CenterPoint Energy continues to propose that UTC time synchronized DFR and DDR data is the final analysis tool and that, given the infrequent nature of wide area events, breaker state change SER data obtained from EMS systems provides adequate resolution for the initial phases of event analysis investigation. In CenterPoint Energy's opinion the SDT has not provided sufficient justification to require such high resolution data in regards to breaker open/close SER data. While CenterPoint Energy recognizes this fine level of data may enhance analysis of a wide area event, the 2003 Blackout as well as other analysis' of more recent wide area events indicates that this level of data is not critical to performing an accurate event analysis. CenterPoint Energy is concerned that this requirement may lead to applicable entities having to install additional SER equipment, communications infrastructure, or data gathering devices to be used only in the rare event that a wide area system disturbance occurs. Therefore, CNP recommends removing SER data from R10.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Disturbance monitoring requirements should be established by the Regional Entity based on their overview of the BES, and monitoring equipment installed and maintained by the TO's to meet the requirements. GO's shoeuld not be included in the standard.
Individual
Andrew Gallo
Director, Reliability Compliance

Yes
City of Austin dba Austin Energy (AE) does not agree with this standard as a whole because it is too prescriptive and unnecessary in the ERCOT Region. Regional requirements for the ERCOT Region regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1. (http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring and analysis. AE recognizes, as the SDT pointed out, the ERCOT requirement is not a NERC Reliability Standard. However, AE disagrees with the SDT's comment that the ERCOT requirements are not enforceable. Entities in the ERCOT Region must comply with the ERCOT requirements or face penalty by the Public Utility Commission of Texas (PUCT). Further, compliance with ERCOT requirements is monitored and enforced by Texas Reliability Entity, Inc. (Texas RE). AE suggests the SDT consider a regional variance for the ERCOT Region, because sufficient requirements already exist.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Regarding requirement in 5.1.5: This requirement is very vague - "major voltage sensitive area" is not a defined term. I Recommend it be revised to reference UVLS programs that are required to maintain compliance with the TPL standards, or possibly place a MW limit of 300 or more MW of load shedding to qualify for consideration.
Group
Puget Sound Energy
Dianne Gordon
Yes
Yes
Yes
a) R3 could refer to R4 (see R4) in regards to details for each triggered FR. b) R8 discusses "continuous data and storage", whereas R11 states that data shall be retrievable for 10 days (presumably following an event), as data retention for longer is expensive and unrealistic. The statements in R8 and R11 may need clarification as to how much data needs to be held in memory before it is overwritten. Data from a catastrophic event may fill a recorder much more quickly than baseline data.
Individual
Glenn Hargrave
CPS Energy
Yes
Yes
While the revision is acceptable and allows the use of microprocessor relays, it would be much better to simply state an accuracy of the data as opposed to the device. With the way it is currently written, potentially a device itself could be synchronized very accurately to a clock while the data it records isn't required to have a specific measure of synchronization accuracy seems odd.
Still feel that the method for determining the busses is too complicated. While we agree that the methodology needs to have consistency, it needs to be made simpler. The spreadsheet is terrible. The examples are difficult to follow and a guide with screenshots needs to be provided to help follow along. For example, how does B3 become a hard-coded example of 64 in both examples when there

is nothing in the instructional steps indicating that this value needs to be changed? With hard to follow example, how can we be confident that we are following the procedure correctly to stay in compliance with our own data? The spreadsheet should be simplified to have users enter data without the zero busses, this may help to reduce the number of steps. A better way would be to write a program or something or make the planning coordinators produce the values generated by the spreadsheets. Also, bus fault MVA needs to be defined. Is this based on fault current and nominal voltages or pre-fault voltages? Are there any modeling requirements for generating the fault values? What needs to be recorded for each event - every terminal at a recorder location or just the faulted terminal? If we have microprocessor relays with GPS clock synchronization at every terminal in our system, would that be adequate enough - to capture each fault at the terminal where the fault was located?
Group
SPP Standards Review Group
Shannon V. Mickens
No
Part 5.2 - We do not fully understand exactly what Part 5.2 is requiring. The rational for Part 5.2 states that a ‘Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous System Demand.’ This we understand. The confusion comes from the phrase ‘inclusive of those BES Elements identified in Part 5.1’. Does this mean the Elements selected must come from those Elements identified in Part 5.1? If that’s the case, we suggest changing the phrase to ‘from the BES Elements identified in Part 5.1’. Additionally, tying the requirement for DDR data to 3,000 MW of load seems arbitrary. Does the DMSDT have any data or other justification supporting this requirement? Wouldn’t it be more meaningful to tie this requirement to system topology and connectivity? Rationale for R5 - Use lower case ‘standard’ in the 2nd line of the 4th paragraph. Insert ‘of’ between ‘understanding’ and ‘why’ in the last line of the 1st paragraph.
No
We suggest the wording in R10 be changed to read: ‘...identified in Requirement R5 to meet the following:’.
PRC-002-2 Thank you for the clarification in the Applicability Section regarding the use of ‘Responsible Entity’. Rationale for R1 - In the 3rd line of the 4th paragraph, the phrase ‘...into the in force list,...’ is used. Shouldn’t this be ‘...into the currently enforced list,...’ or ‘...into the current list,...’? Also, there is a font issue with the inserted sentence. Rationale for R4 - Hyphenate ’30-cycle total minimum record length’ and ’30-contiguous cycles’. Rationale for R11 - Insert a hyphen and a space in ’10-calendar day’ at the beginning of the 2nd line of the 3rd paragraph. Attachment 1 R1, Step 7-Thank you for the additional clarification in Step 7. Guideline for Requirement R4-Hyphenate ’30-cycle record length’ in the 4th line of the 1st paragraph and ’30-contiguous cycles’ in the last line of the 1st paragraph. We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. We would ask that the drafting team take into consideration our suggestion to review the language mentioned in reference to the term ‘list’ in Attachment 1. Our concern at this point would be.... the term presents some confusion in how it’s being used in the Steps of the documentation. For example in Step 3, we are not sure what ‘list’ you are referring to and will this term take on the same meaning as mentioned in the previous Steps (1 and 2)? We would request that you provide more clarity on which ‘list’ you are referring to and what data should be included in this process.
Group
DTE Electric Co.
Kathleen Black
No
The MVA level for generation is still a concern, but it is understood that this change will not be considered by the SDT. Will the Responsible Entity work to insure that the DDR equipment at shared GO/TO facilities is not duplicated? Also, it is suggested that the Responsible Entity include in their identification criteria an evaluation of monitored quantities versus installation expense. It seems unreasonable to require DDR data at a location where only two monitored quantities are needed.
No Comments

No Comments
Individual
John Merrell
Tacoma Power
No
Tacoma Power agrees that most of the revisions outlined above are improvements but we still believe that the standard as written requires utilities to spend more effort documenting data recording than necessary to reliably operate the BES. For example, within the WECC footprint there are 49 generators in WECC that meet the 500 MW threshold in R5.1.1.1. The minimum required number of DDRs based on load per R.5.2.2 is 52 generators. Thus the first 1/6th of the proposed requirement provides 94% of the prudent DDRs. Although we have not analyzed exactly how many DDRs will be required for R5.1.2 through R5.1.5, it is clear that the 1 per 3000 MW specified R5.2.2 has little correlation to how many are currently specified by R5.1. Instead, R5.2.2 should provide regulatory certainty by specifying a maximum number of DDRs that would be required to be documented as compliant with this NERC standard. We disagree with the changes to R5.1.5. Although a UVLS program is an indicator of a major voltage sensitive area, UVLS should not be the definition of “major voltage sensitive area.” There are remote portions of the system that may have UVLS, but they would not be classified as “major” since they have significantly less than 300 MW of load.
No
The revision now specifies the properties of the equipment, rather than specifying the accuracy of the SER and FR data. Under the revision, a utility could use the SCADA master at their control center as the SER recorder as long as the SCADA master met the synchronization requirement, irrespective of the communication delays between substations and the control center.
Yes
Although we agree focusing on “what” data rather than “how” data is a good idea, Measures M2 and M3 parts (1) and (3) are not consistent with that philosophy. Documented design specifications or station drawings are not evidence that the owner actually has SER/FR data; these documents are simply evidence of “how” the data might be captured rather than “what” data is actually being captured. In order to address the inconsistency between the requirement and the measure, the term “recording capability” should be inserted after the word “data” in Requirements R2 and R3. As currently written, this standard has a zero defect approach. A single missing piece of data is not a threat to the BES when analyzing historical events. In addition to the PRC-002-2 required recordings, most utilities have been installing microprocessor based relays with data recording capabilities. Requirement R5, Part 5.2.2, does not use the word ‘additional,’ but the Rationale for R5 does. If a Responsible Entity has 3,000 MW of historical simultaneous peak System Demand, are they required to have (at minimum) 1 or 2 locations with DDR? Requirement R5, Part 5.4, requires the Responsible Entity to implement the reevaluated list of BES Elements. However, the discussion in the Rationale for R5 says that the Transmission Owner and Generator Owner are responsible for implementation. It is understood that the Rationale for R5 is what is intended. Requirement R5, Part 5.4, ought to be amended to be consistent. In Measurement M9, it appears that the text “(R9, Part 9.1)” may be missing. In Requirement R11, Part 11.2, change “...unless and extension...” to “...unless an extension...” Requirement R11, Part 11.1, will likely drive (1) automatic event retrieval from relays used for FR/SER, (2) restriction of event triggers in relays (to the detriment of the entity’s other business objectives as they try to assure compliance for all scenarios), and/or (3) installation of dedicated FR equipment (or new relays) with large buffers. Buffers in many types of relays used for FR/SER could easily be overwritten within 10 calendar days, depending upon what event triggers are set up and power system conditions. It seems like the implementation plan for Requirements R2-R4 and/or R6-R11 in response re-evaluated lists from Requirement R1 or R5 should be included in the body of the standard. Implementation Plans are normally valid only for the initial phase-in of a standard (or new version of a standard). The response to a re-evaluated list is an ongoing activity.
Group
National Grid
Michael Jones

No
R5 / R5.1.2 may result in the implementation of more DDR equipment than is necessary for wide-area disturbance event analysis. Preliminary Planning Coordinator analysis indicates this concern.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
ERCOT agrees with the changes made to the BES Elements requiring data listed in R5, but have a concern over the other changes to R5 (and R1). Please see the comments provided in response to Q3.
Yes
Yes
ERCOT generally agrees with all the proposed changes and proposes some additional clarifications as provided below: • The addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. • R5.1.4 should be revised to state: One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). • An additional sub-requirement should be added as R5.1.6, stating: 5.1.6 Any one BES Element that has previously demonstrated localized dynamic oscillations. • An additional sub-requirement should be added as R 5.1.7, stating: 5.1.7 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. • Additionally, ERCOT respectfully submits that the RC/PC does not implement the plan, the TOs/GOs do (see paragraph 5 of Rationale for R5.) Accordingly, ERCOT recommends that R5.4 be revised to strike the last phrase as shown below: 5.4 Reevaluate all the identified buses BES Elements 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, and implement the reevaluated list of BES Elements as per the Implementation Plan. • Requirement R8 should include a trigger for dynamic oscillations with less than 5% damping (whether local or inter-area). Requirement R8.2 should be reworded to identify triggers that are appropriate for the reasoning for the DDR identified in R5. For example, it is more appropriate for the trigger to be based on voltage for voltage sensitive areas. Gen locations would most likely trigger off (at least) frequency. ERCOT also recommends that the SDT consider the appropriate trigger for angular stability locations. For ERCOT, the off nominal frequency trigger should be set at 59.4 and 60.6 for ERCOT. This would give some additional bandwidth before entering 1st stage UFLS and catch the high frequency setpoint where generators should not trip off within 9 min. Additionally, the undervoltage trigger should be set consistently with that of the UVLS in the area. To set the trigger below the UVLS scheme would not utilize the equipment appropriately and the recording should be utilized to capture any UVLS event that would actually activate.
Group
ISO/RTO Council Standards Review Committee (SRC)
Greg Campoli
Yes
We agree with the changes made to the BES Elements requiring data listed in R5, but have a comment on other changes to R5 (and R1). Please see our comments under Q3.
Yes
No
We generally agree with all the proposed changes. However, the addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and which makes the requirement out of date over time. The implementation

timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot
Group
Bonneville Power Administration
Andrea Jessup
No
R5.1.1 BPA believes gross individual nameplate rating greater than or equal to 500 MVA seems an appropriate measure for DDR as does aggregate gross plant/facility rating of 1000MVA. However, the 300MVA individual nameplate rating appears arbitrary and unnecessary. Facilities with greater than 1000MVA aggregate nameplate rating should have DDR capabilities associated with the point of interconnection regardless of individual unit size. R5.1.4 BPA believes the number of items selected under this requirement must be limited within the standard given that the Responsible Entity is requiring the Transmission Operator to invest money in the installation of DDR equipment and infrastructure based on the selection of “One or more BES Elements.” The Transmission Operator must be given the authority to select alternate elements for DDR monitoring as well the flexibility to defer or refuse to install monitoring on some elements for reasonable cause. BPA believes this would provide a more prudent balance between the need for monitoring and the cost of installation and maintenance.
No
BPA feels the designation of a minimum clock accuracy adds to the compliance burden that must be met by the Owner while providing no incremental benefit to the reliability of the system. Almost all dedicated FR and SER equipment exceeds this threshold making the requirement irrelevant. Relay based event monitoring equipment may not meet this requirement and would therefore need to be replaced while providing no incremental increase in the quality of the data provided. This requirement would be better communicated in a NERC guidance document.
Yes
BPA believes the authority and responsibility for installing Adequate FR, SER, and DDR equipment must be left to the individual TOs and GOs. These are the parties who will fund these, who know the system best and who will ultimately be responsible for the analysis of system events. It is appropriate that the Responsible Entity request desired locations for this equipment but the final siting decisions must be left to the Owner. Transmission and Generation Owners have long known the value of accurate and comprehensive disturbance monitoring for the purpose of system event analysis. BPA believes it is presumptive to assume that this new methodology for FR and SER placement will provide adequate data for system event analysis. Out of necessity most Transmission and Generation owners have already developed proven strategies for disturbance monitoring on their systems. BPA believes this standard should require Entities to develop their own methodology for monitoring. BPA believes Requirements 11.3, 11.4 and 11.5 go too far in stipulating the file format and naming convention for event data submissions. This is in direct conflict with the DMSDTs’ statement: “The standard deals with "what" data is recorded, not "how" it is recorded.” File formatting is an administrative detail and does not warrant regulatory scrutiny. BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance responsibility with respect to this standard. As written, the notification requirement in R1.2 places an undue compliance risk on TOs and should be removed. BPA also believes the rationale of R3/M3 is a little flawed (if more than one GSU source is connected to the bus then excluding 4 won’t allow direct derivation of total fault current on the bus. This would be indirectly derived by comparison of the fault study results.
Individual
Larry Heckert
Alliant Energy
Yes
Yes

Consider revising Requirement R8 so that it refers to continuous recording and storage necessary to meet Requirement R11. Otherwise, it leaves the interpretation open that the user needs continuous unlimited storage of data.

Additional Comments:

JEA
Thomas McElhinney

We believe that the threshold of 1500MVA is too low

GASOC
Scott McGough

We support ACES Power Marketing comments with our negative ballot