Individual or group. (73 Responses)
Name (42 Responses)
Organization (42 Responses)
Group Name (31 Responses)
Lead Contact (31 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (73 Responses)
Question 1 (57 Responses)
Question 1 Comments (67 Responses)
Question 2 (54 Responses)
Question 2 Comments (67 Responses)
Question 3 (57 Responses)
Question 3 Comments (67 Responses)
Question 4 (56 Responses)
Question 4 Comments (67 Responses)
Question 5 (44 Responses)
Question 5 Comments (67 Responses)
Question 6 (55 Responses)
Question 6 Comments (67 Responses)
Question 7 (0 Responses)
Question 7 Comments (67 Responses)

Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes
Yes
Yes
Yes
No
Protection Engineering: The 4 year implementation plan could be challenging to fit into our project process. We employ a 3 year cycle with definition in year 1, scope/design in year 2, and construction in year 3. Any delays in any given year could cause us to exceed the requirement.
As related to R5.1, we wonder if there is a need for both bulleted items. We are assuming that these two bulleted items represent an "OR" otherwise they would be listed as two separate Req. Further, if "At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault" is sufficient, why is there an option to capture 50 cycles of data? We also request clarification of R8 to either explicitly allow or not allow the power measurements to be calculated from the voltage and current used in 8.1 & 8.2. In the WECC footprint, we believe Sequence of Events is typically abbreviated SER.
Individual
Brenda Frazer
Edison Mission Marketing & Trading Inc.

Yes
Yes
Yes
Yes
Yes
Yes
While we believe that our Wind sites have a low risk of being one of the selected entities required to install & maintain disturbance monitoring equipment, the standard provides no compensation for the purchase, installation, and maintenance of this equipment. It may a significant burden on our projects.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
Yes
No
R2 and R7 have 10 day time limits before elevating to the next Violation Security Level. This is too short and should be increased to 30 days.
Yes
The proposed standard still needs work before it is acceptable. The following items need to be addressed: 1. The standard requires all owners of identified BES elements to implement the various types of recording. However, for jointly owned facilities, this puts co-owners in a position whereby they can be held in violation of the standard if the operating/maintenance entity of a co-owned facility does not implement and maintain compliance with the standard. For jointly owned facilities, the standard should specifically address which of the co-owners (preferably the co-owner that operates or maintains the facility) is responsible for compliance with the standard. 2. Requirement 14 needs to be re-written. As it is now written, R14 requires that a TO or GO formally report to the Regional Entity an outage of any of the recording capabilities covered by the standard along with a Corrective Action Plan. However, in the “Rationale for R14” discussion that is included it is clear that the intent or this requirement is to require the TO/GO to report the problem only if they cannot restore the lost recording capability within 90 days. The requirement needs to be re-written to state the actual intent because as it is now written, one must contact the Regional entity every time the recording capability goes out, no matter how long it went out for. 3. Requirements R10 through R13 all seem to be required specifications and shouldn’t have their own requirements but could rather be combined into an Appendix to the standard. 4. The standard should allow for monitoring/recording up to the capability of the equipment presently installed (this is not referring to the capability of the presently installed recording capability but rather the presently installed BES equipment capability). A utility shouldn’t have to install major equipment (CCVTs, breakers, etc) just to meet the standard

if their presently installed equipment doesn't allow adequate monitoring. 5. In Requirement R3 it is not clear if a GO will be required to monitor a low side generator breaker. The standard refers to breaker connected to the identified bus location. If this refers to each breaker that is directly connected to the bus location, the requirement should use the term "directly". Without qualifying as such, the question remains as to whether the low side breaker qualified as being connected to the bus since it is connected to the bus through the GSU transformer.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Yes
Yes
Yes
Yes
Yes
No
1) Implementation for Requirement R14, as presently written, applies 9 months after the standard is approved. This requirement needs to be clarified. It should only apply to those SOE, FR, and DDR devices that have been installed in accordance with, and meet the requirements of, this standard. Legacy DME equipment that may exist at one of the busses identified in R1, which does not meet the requirements of this standard, should not be subject to Requirement R14, until the equipment is upgraded, or replaced, to meet the full requirements of this standard. This clarification needs to be made, or, the implementation for R14 should be moved to coincide with the timetable for Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13. 2) The timetable for implementation of Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13 allows an entity that owns only one bus location four years to achieve compliance. However, Entities must be compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three years following notification of the list. Why this discrepancy? Four years seems appropriate in both cases, in order to schedule the numerous outages necessary to install the equipment, particularly if generation units are connected to the bus.
1) Requirement R2 should be re-written as follows: Each transmission Owner that identifies BES Elements, which are owned by other entities, at the locations established in Requirement R1 shall notify the owners of those Elements ….. By adding the phrase - which are owned by other entities - eliminates the need to unnecessarily provide documentation that it notified itself of the requirement. 2) Requirement R4 Part 4.1 should be re-written as follows: Phase-to-neutral voltages for each phase of either each BES line or bus. The term BES must be added to provide clarity and to be consistent with Part 4.2 and the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide voltage monitoring on non BES radial lines, or distribution transformers connected to the bus. 3) Requirement R8 should be re-written as follows: Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES radial lines, or distribution transformers connected to the bus. 4) Requirement R9 should be re-written as follows: Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES station service transformers connected to the bus. 5) Requirement R13 Part 13.2 poses an

indeterminate requirement on the size of the hard drive required to archive data. The present requirement states that the data will be retrievable for the period of 10 calendar days preceding a request. However, there is no requirement on how long after an event the request might be made. If the request was not made until six months after the event, would the data have to be retrievable for six months after the event? In order to place certainty on this data storage requirement Part 13.2 should be re-written as follows: The recorded data will be retrievable for a period of 10 calendar days following an event. This places a limit on data storage capacity and also makes it clear that a request for data must be made within 10 calendar days of the event. 6) Requirement R14 needs to be re-written to be consistent with the intent of the requirement as expressed in the shaded box describing the Rationale for R14. As presently written, R14 requires that the Owner must both restore recording ability AND report the inability to record data to the Regional Entity. To be consistent with the Rationale, Requirement R14 should be re-written as follows: Each Transmission Owner and Generation Owner, upon discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and elements as per Requirement R7, shall restore the recording ability within 90 calendar days, OR , if the recording capability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability. 7) In the Guidelines and Technical Basis in the next to last paragraph of the section on Guideline for Requirement R1 it states that there is no requirement for SOER and FR for generating units. Later in the section on Guideline for Requirement R4 it states that generator step-up transformers are excluded from fault recording. If so, why is Generator Owner listed as an applicable entity in Requirement R4? It makes sense to list them in R3, since they may own breakers connected to Transmission Owners bus, but the GSU Transformer, station service transformer, and generator itself would not qualify for Fault Recording. 8) There is no specific requirement for the sampling rate for SOER within the standard itself. In the Guidelines and Technical Basis section on Guideline for Requirement R5 it states that a minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER. There are a vast number of microprocessor relays currently installed on the system that have a sampling rate of 16 samples per cycle for analog inputs, however, the digital inputs, which would be used for SOE recording, are only sampled every quarter cycle. Existing regional DME standards and criteria recognize this and permit these types of microprocessor relays to be acceptable for both FR and SOER applications. As such, in order to allow these devices to continue to be an acceptable application, we would suggest two requirements be added for SOER devices, similar to that included in the RFC DME criteria, that states: SOER recording equipment should be capable of determining and recording the time that an input is received to within one quarter of an electrical cycle (or less) of input change of state. SOER recording equipment should have time stamp capability to record seconds to at least three decimal places (i.e. ss.000). 9) The bus selection methodology in Attachment 1 defines a single bus location as including any bus Elements at the same voltage level within the same physical location sharing a common ground grid. However, there are some substations that have multiple busses at the same voltage level within the same physical location that share a common ground grid, but are not physically connected together. They are either physically isolated from one another, or connected via a normally open tie switch or breaker. In these cases, the above definition does fit this scenario and each bus should be evaluated independently. To address this scenario perhaps the definition should be re-written as follows: A single bus location includes any bus Elements at the same voltage level that are connected together within the same physical location sharing a common ground grid.
Individual
Dan Roethemeyer
Dynegy
Yes
Yes
No

1.) Regional Standard PRC-002-NPCC-01 which recently became effective conflicts with PRC-002-2. There is no bright line 500 MVA criteria for GOs to install DDR in the NPCC Regional Standard which instead allows the Reliability Coordinator to make the call. Also, it is not clear from R6 if the GO is supposed to wait for notification from the RC to install DDR or if the GO should go ahead and install DDR at units >500 MVA on their own. 2.) It's recognized that the SDT researched the 500 MVA cutoff point to cover what was felt to be an appropriate percentage of US generating assets. Based on comparisons with other Regional Criteria and Standards, this number seems low – some use a number of 1000 MVA. A compromise cutoff of 750 MVA is suggested. 3.) PRC-002-NPCC-01 requires installation of SOER and FR at generating units while PRC-002-2 specifically states SOER and FR are not required at generating units. Some GOs have spent considerable capital dollars to comply with a new NPCC Regional Standard, only to have a new conflicting continent wide Standard proposed.
No
The two/three/four year requirement for a GO to be 25%/50%/100% compliant should be increased to three/four/five years to give more time to budget these large capital expenditures.
Regional Standard PRC-002-NPCC-01 technical specifications for DDR conflict with PRC-002-2 technical specifications. The NPCC Regional Standard R9 specifies a DDR recording rate of 6 times per second while PRC-002-2 specifies 30 times per second. Conflicts with the Regional Standard should be removed so entities are not penalized for Regional Standard compliance.
Group
Modeling Working Group
Jose Conto
Yes
MWG finds that requirements for data retention are essential to this standard but are missing in the current draft. MWG recommends including a requirement that all triggered data recordings be retained for a minimum of 2 years and that all continuous data recordings be retained for a minimum of 30 days. MWG also recommends including a requirement that all continuous data recordings be scanned against the set of triggers defined in R10 and those portions of the continuous recordings that fall within the time periods defined by those triggers be retained for a minimum of 2 years.
Group
Northeast Power Coordinating Council
Guy Zito
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances". We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis. We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should

be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase “... status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.
Yes
We agree with the idea behind the methodology, however the term BES bus locations is not defined. The NERC BES definition applies to Elements, not buses. Continuing to Requirement R2, a TO might not have visibility to BES classification of elements it does not own. Planning/Reliability Coordinator would be a more applicable functional entity for this role. They should also be responsible for reaching out to the GO’s with notification for SOER and FR. A TO has no authority to perform this function; a GO might also question the bus selection and ask that another TO bus be included instead. The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add “discretionary” stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station’s fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,...). The term “bus” can be defined in different ways, so can “location.”
Yes
No
Requirement R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but sub-Parts 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., sub-Parts 6.1.1 and 6.1.2), and one for the location/element (sub-Parts 6.1.3 to 6.1.6). Suggest moving the minimum quantities in sub-Parts 6.1.1 (minimum 1 DDR per 3000 MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for sub-Parts 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc...), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 do not meet the two extra minimum quantities requirements. Sub-Part 6.1.3--Needs to be clarified to make it understood how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples would be helpful. Sub-Part 6.1.4, first bullet – Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. For example, the NY-NE interface is one of the official NERC Flowgates, which means that entities will need a DDR at each of eight stations that interconnect with New York; while entities on the other end of the interconnection in NE will need to do the same. Regarding “monitor all Elements of: all permanent Flowgates”. If a Flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (low side or high side side)? Please show some typical examples. The guideline for R6 included in the draft fails to explain why all Flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum pre-contingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with sub-Part 6.1.3.2 because there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Clarify that DDR is for “all permanent Flowgates” ONLY if the Flowgates are BES Elements. Sub-Part 6.1.5 – this will require the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in sub-Part 6.1.3 (500 MW). This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities. Sub-Part 6.1.6 – This requirement could

lead to installation of DDRs at many substations to just capture one flow that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. Sub-Part 6.1.6/Guideline - The Guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will dramatically increase the number of the DDRs need to be installed. This could cause too excessive burden on some TOs. Also, there is nothing to limit the burden which can be placed on the TO by a Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable). Depending on the impact, a 3-year implementation plan might not be achievable.
No
The VSLs don’t take into account the size of responsible entity. Larger entities should be given more time.
No
Recommend updating the “entity” for the following requirements on the Implementation Plan Summary: R8 - TO R9 - GO R10 - TO/GO The Implementation Plan doesn’t take into account the size of responsible entity. Larger entities should be given more time (see response to Question 5).
Regarding Attachment 1: a) The term "BES bus location" is not clear. There could be two or more BES bus locations at the same physical location (substation). The definition of "BES bus" could not be found. b) Step 7 of Attachment 1 does not specify how to round the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. c) Step 8 of Attachment 1 does not specify how to round the additional 10% of the BES bus locations determined in Step 6. d) Attachment 1 does not specify how to distribute an odd number for 20% of the BES bus locations between b) and c) from above. In Part 1.2 and Part 6.2, what prevents a TO or RE from assessing the locations and elements too frequently? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability where monitoring is really needed. Frequent assessments could move locations above and below the minimum criteria line and create confusion. We agree with R1, but do not see the need for R2 because through R1 and Attachment 1 each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the “list of BES bus locations that it owns” stated in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that’s the case, Step 1 in Attachment 1 needs to be clarified. In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say “Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…”. If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. The intent of Requirement R2 is for Transmission Owners to notify “other” owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, suggest revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the “other” owners of those Elements… M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to “other” owners of Elements… Requirement R3 specifically asks to have SOER, however the guideline for R3 allows for the breaker status to be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R4. This should be identified in the Requirement itself. The guideline is a non-binding portion of a standard. The guideline for R3 has a typo (it should reference R4 instead of R14). Requirement R4 is not clear if determine means that the required BES Elements of TO and GO shall have waveforms for each phase current and the residual or neutral current. Regarding Requirement R4, Part 4.2, it is not clear if only high-side voltage winding voltages and currents need to be recorded. Clarification is needed if low-side voltage windings and transformer neutral need to be monitored also. Part 4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – “…. Voltages for each phase of either each line or bus.” which could be confusing. Part 4.2 – Residual current and neutral current

are two different quantities. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the Drafting Team). Sub-Part 4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. M4 (1): add “plus evidence the device was commissioned at the specific bus in question”. In Part 5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following:”. Part 5.1 – the two bullet items in this requirement are confusing and should be reworded to clarify what is intended. Part 5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. Part 5.2 assumes that SOE recording is driven by DFR analog sampling since it infers the achievement of a 1ms digital event resolution for a 960Hz (16x60Hz) analog sample rate. Stating analog and event resolution requirements (i.e. 16 samples per cycle and 1ms event resolution respectively) separately and explicitly is clearer and accommodates instances where SOER is separate from analog sampling. Part 5.3.1. asks to have trigger settings for neutral (residual) overcurrent, which implies for R4 that it is necessary not only to determine but to monitor either each phase current or neutral current. Regarding requirement R6, the standard should not create a new term like “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. If the Drafting Team decides to retain sub-Part 6.1.6, then it is recommended the phrase "all Elements associated with Interconnection Reliability Operating Limits" be replaced with "elements critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" similar to the language used in CIP-002-4. CIP-002-4 - Attachment 1 Critical Asset Criteria reads: 1.8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The Drafting Team has mapped this requirement to R14 of PRC-002-2. These two activities are not the same since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. R14 of PRC-002-2 requires entities to repair equipment that they know is in a failed state. The Part 8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the Drafting Team correct this requirement by referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions Real and Reactive Power could be determined. The design should be assuming all normally-closed circuit breakers on a bus are closed. This avoids being out of compliance during a specific event, if open bus breakers preclude recording the MVA flows on all elements. Requirement R10 should allow the legacy equipment to have multiple triggered records which make up the required length. It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? R13 – this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? Requirement R13, Part 13.3. asks for SOER data in Comma Separated Value (.CSV) format whereas the majority of Disturbance Monitoring Equipment (DME) do not save data in this format. In addition, if breaker open/close position determination from FR data is acceptable, no .CSV file can be created by the recording tool itself. There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on

Attachment 2 below). Similarly, R13 Part 13.4. asks for FR and DDR data in C37.111 , IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet – “If recording ability is not restored within 90 days, report the inability...” The Rationale for requirement R14 recognizes that the DME equipment cannot be always returned to service within 90 calendar days of the discovery of a failure. Requirement R14 itself, however, is not clear and should be rewritten to reflect 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, 2013, NPCC applicable entities are two 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 with this Regional Reliability Standard. 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. Regarding Attachment 2, the format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Group
North American Generator Forum - Standards Review Team (NAGF-SRT)
Allen Schriver
Yes
No
Modify the applicability section 4.3 by adding the following parenthetical after Generator Owner: (“Applies to GO only if GO owns a generator output breaker in the TO’s system”) We made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. The webinar presenters stated that this would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. We disagree in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of ’03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO’s system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach WebEx meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don’t understand.

No
Disagree. Smaller generators who may be drawn into the standard are likely to have only one location to install equipment. This would require 100% compliance within 2 years of notification. If notification occurs soon after a major outage, the generator may be forced to take an unneeded outage just to comply with the standard. Suggest adding the following: For entities with fewer than four locations identified by the TO, entity shall be 100% compliant within four years with no compliance required prior to that date.
1. It appeared from the 11/19/13 webinar that the R9 obligation for GO's to "have" DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comment to question #3 above. Additionally, it is not clear in R9 whether the specification for signal measurements is on a per generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). This determination weighs heavily on the cost and method of implementation where new equipment must be installed. 2. R6 sets DDR applicability criteria based on the "nameplate rating," but doesn't say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, "Facility Rating," as defined in FAC-008 should then be used to avoid confusion. 3. The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent spurious triggering of the DME. We suggest three cycles. 4. R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. Additionally, R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record.
Individual
Rick Terrill
Luminant Generation Company LLC
Yes
Yes
Requirement R4 as written could require both the Transmission Owner and the Generator Owner to monitor the requested electrical quantities for all lines and elements at the bus or switchyard where the generator is interconnected. R4 needs to be re-written to clarify that the GO is only responsible for monitoring for faults on the equipment it owns and the same for the TO. For Requirement R13, subsections 13.3, 13.4 and 13.5 should be deleted from the standard entirely. These items are completely administrative in nature and are not results based. An entity could make a typo mistake

in formatting or when naming a file and be non-compliant with the requirement. Also, the sub-requirements 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. Finally, the standard is written in a confusing format where twelve of the 14 requirements in the standard reference other requirements, which in many cases reference another requirement (or two). As a GO, I need to know, in a clear concise manner, what electrical quantities or status I need to monitor where, and what attributes are needed for the disturbance monitoring equipment
Group
Hydro One Networks Inc.
Sasa Maljukan
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances”. We don’t see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
No
This requirement (and associated Attachment 1) requires some clarity before we can determine if we agree with the methodology. This may be a bit problematic with the BES definition not confined to busses. What is a BES bus location? Does this mean the entity gathers information on all fault levels for busses which contain at least one BES Element?
Yes
No
1. R6.1.4, first bullet – Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. 2. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities 3. Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.
Yes
Yes
1. R5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not

directly monitoring it. 2. R4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – “…. Voltages for each phase of either each line or bus.” which could be confusing. 3. R4.2 – Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). 4. R4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. 5. There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. 6. R13 – this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? 7. R8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. 8. R3, R4, R12, R13, R14 all reference “the bus locations as per Requirement R2” however this requirement is a notification requirement only for Elements not owned by the TO that need DME. These requirements need to reference both R1 and R2 pending changes to R1/R2. 9. The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 is to identify busses for DME. It should probably be expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO. 10. R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 11. R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above) 12. Section 1.2 - Evidence Retention: Second sentence states:” For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.” . To avoid confusion we recommend that the SDT removes “may ask” and provide further clarification on what evidence needs to be retained and for how long. One approach would be to make a retention period to be “greater or longer of” the period since the last audit or the list below. 13. Section 1.2 - Evidence Retention: To avoid confusion we suggest that the retention period for R1/R2 and R6/R7 is specified as “current version of the list” or “current and previous version of the list”. This will avoid confusion associated with the five years retention when the list is produced at a 5 year cycle.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
1. DDR definition: The phrase "abnormal voltage problems" is redundant. Suggest definition be changed to: The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, or abnormal voltage conditions. 2. SOER definition: Need to specifically identify circuit breakers, which are the primary Elements needed for SOER as indicated in Requirement 3. Suggest it be changed to: The recording of time sequenced data for change in status of Elements, particularly circuit breakers, and including other protection and control devices as needed.
Yes

Yes
Yes
No
Item 5 This item references a nine month timeframe associated with R14. There does not appear to be any such timeframe listed under R14. Since the required in-service dates for DME are from two to four years, that timeframe should determine the compliance date for R14.
In Requirement 14, there is a discrepancy between the text of R14 and the Rationale statement which follows. The bullet “Restore the recording capability” should be changed to “Restore the recording capability if possible”. This will allow the entity more time if necessary to correct the problem, which is allowable as described in the Rationale. As it stands, an entity will be in violation if the recording capability is not restored within 90 days of discovery of a failure.
Individual
Kayleigh Wilkerson
Lincoln Electric System
LES recommends the drafting team further clarify the bus selection process included in Attachment 1. As drafted, the current Attachment 1 methodology does not appear to account for substation configurations such as a 115kV tap bus with a radial transformer fed from that bus. Although the radial transformer would not be considered a BES Element, the bus would be considered BES since it carries through-flow on the line. At this substation, there is no relaying and therefore no capability for SEOR or FR. In consideration of this, does the drafting team intend for this type of bus to be included on the list? By including these busses, the total number of busses, and therefore the total number of substations requiring SEOR and FR, would increase considerably for some entities.
R13.2 specifies that “The recorded data will be retrievable for the period of 10 calendar days preceding a request”. As drafted, this requirement seems to indicate that if an event happened on June 1st and the data was requested on June 30th, then the data would have to be retrievable from June 20th to the 30th. However, if a request is made on June 6th following a June 1st disturbance, it would not be possible to comply with the 10 calendar day requirement. Unless LES misunderstands the drafting team’s intent, it seems as though the requirement is meant to ensure that data is available and retrievable for a period of 10 calendar days following a disturbance in the event further analysis needs to be conducted. To ensure this intent is conveyed, LES recommends rewording R13.2 to indicate that the 10 day period starts at the time of the event. Additionally, R13.2 should also account for circumstances beyond the control of the TO or GO in which multiple events caused the relays recording the data to overwrite it with more recent events due to limited memory space. As an example, a TO could have information available for the 10 days required by the standard, but multiple disturbances due to severe weather on day 12 resulted in initial data being unavailable for a request initiated on day 12 or later. If this occurs, R13.2 would then place the Transmission Owner or Generator Owner in violation of the standard due to a limitation inherent to the relay. 13.2. The recorded data will be retrievable for the period of 10 calendar days following a disturbance.(1) Footnote (1): The 10 calendar day period may be waived for circumstances beyond the control of an applicable Transmission Owner or an applicable Generator Owner, such as, but not limited to, equipment manufacturer limitations resulting in the loss of data.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.

Agree
NPCC
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communication the list to, unless the "list of BES bus locations that it owns" depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that's the case, Step 1 in Attachment 1 needs to be clarified.
Yes
No
R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for "Elements", but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6). Requirement R6.1.4 - The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities. Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.
Yes
Yes
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
Yes
Yes
Yes

Yes
Yes
Individual
Thomas Foltz
American Electric Power
No
Sequence of Events Recording (SOER) – This definition should only specify functionality and *not* attempt to define scope. Instead, we suggest "The recording of time sequenced data for change in status of a monitored, binary value". Fault Recording (FR) – Again, this definition should only specify functionality and *not* attempt to define scope. Instead, we suggest "The recording of time-sequenced waveform data for a monitored analog value."
No
Fault analysis programs such as ASPEN include tap busses to provide connection points for distribution transformers, series capacitors, three-terminal lines, etc. Since these connection points do not have circuit breakers associated with them they are not appropriate locations for disturbance monitoring. However, when applying the Attachment 1 process, these tap busses could show up and possibly distort the Attachment 1 data. The fault summary feature in ASPEN has a check box to ignore tap busses. AEP requests that this feature be utilized in the Attachment 1 process. AEP is concerned that the "top 10%" requirement could force the installation of fault recording devices to be installed at a station with only 2 BES sources. An example is a protected load bus with only 2 BES elements that is connected to stations which meet the requirement and have fault recording devices installed. In this case, both of the stations remote to the protected load bus are BES buses in the top 10% of a TO's bus listing. The standard should not require DFR/SER at those locations. AEP's position is that the standard should focus on fault information availability after an event that allows for accurate analysis and not on over-saturation of fault recording equipment that will require monitoring and maintenance to ensure that the equipment is in service when needed. R2 states that TOs must notify owners of Elements that those elements require SOER/FR. However, the process identified in R1 does not establish a requirement to identify BES Elements. This does not account for the fact that not all elements on the identified busses should require SOER/FR. AEP suggests that the SDT add a new R1.3 to state "For each bus identified per 1.1, the Transmission Owner shall identify the BES elements that require FR and the BES interrupting devices that require SOER". The draft can be interpreted to require TOs to dictate to GOs and IPPs where they must install FR/SOER. AEP believes it would be inappropriate for TOs to specify FR/SOER locations for GOs and IPPs. While Attachment 1 provides a reasonable method for TOs to produce a list of buses that it owns, R2 will make TOs responsible to keep track of elements within those buses that it does not own. This responsibility should be revised so that TOs can focus on ensuring that they have adequate equipment in place to monitor its system, rather than managing the complex logistics needed to notify GOs and IPPs.
Yes
No
This listing appears far too prescriptive by going beyond the "what's" and specifying the "how's". In the application of R6, the Responsible Entity should consider existing DDR installations when determining where to require DDR. There may be existing installations that can satisfy the R6 criteria. At a minimum, it might be beneficial to add such considerations to the "Guideline for Requirement R6" section. It is unclear whether DDR is required on all generating resources or only some generating resources that meet the requirements of R6.1.3.1 and R6.1.3.2. We suggest changing the title of Section 6.1.3 to "All generating resources with:" to be consistent with the other sections.
Yes

No
We believe the implementation plan will be sufficient, however we cannot state that with absolute certainty until the completion of the identification processes in R1 and R6. At this time, the actual scope is still unknown.
In general, we believe the standard is written to prescriptively when the standard emphasizes post-event analysis. More clarity is needed regarding time frame, etc. as to what is expected of a TO after they informed that data recording is required for an element owed by the TO. R13.1: Suggest “The recorded data will be provided within 30 calendar days, or other agreed-upon timeframe, of a request.” It appears that R2 applies to shared stations only. If this is accurate, we suggest rewording to clarify the intended applicability. In addition, it is unclear which entity would be responsible for the installations. The wording in R13.2 is unclear. Possible interpretations include that the data must be retrievable for at least 10 days at any given time, or that the data must be retrievable on a continuous basis. Please revise to provide clarification. The sub-bullets listed in R13, especially R13.2, would be more appropriately included in the technical requirements of each DME type in R3, R5 and R11. The sub-bullets in R14 read do not clearly read as an OR statement and may be misinterpreted as an AND statement. We recommend removing the bullets and making the item read as a single sentence: “… shall restore the recording ability or report the inability to record data…” R3 requires GOs and TOs to install SOER for each circuit breaker they own that is connected to the bus locations identified in R1. This does not account for the fact that not all of the circuit breakers on the identified busses should require SOER because some breakers may be associated with non BES equipment. R4.1 should be modified to state “Phase-to-neutral voltages for each phase of either each specified line or bus.” In R5.1, an “or” should be added to the end of the first bullet to improve clarity. Also, in R5.3 the word “settings” should be removed to improve technical accuracy. In R7, the word “determination” should be replaced with “identification” to be consistent with the rest of the standard. R8 should be revised as follows to improve clarity: R8.1: “At least one phase…” R8.2: “The current on the same phase as the voltage in…” R8.4: “Frequency of at least one of the…. R9 should be revised as follows to improve clarity: R9.1: “At least one phase…” R9.2: “The phase current on the same phase as the voltage in…” The drafting team may want consider combining requirements that are related to the same monitoring equipment types. R4 and R5 could be combined because they both relate to specifications of FR equipment. Similarly, R8, R10, and R11 could be combined, as they all relate to DDR equipment.
Individual
Scott Langston
City of Tallahassee
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Kathleen Goodman
ISO New England Inc.

No
Comment on R6 – The standard should not use the term “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. Comment on R6.1.4 –Requiring monitoring of all Elements of “Flowgates” on the Eastern Interconnection seems arbitrary and may miss important locations for DDRs, especially for areas that do not use flowgates. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. This requirement will also lead to installation of equipment that provides practically no value to the Purpose of this standard. For example, the NY-NE interface is one of the official NERC Flowgates, which means that ISO-NE will need a DDR at each of eight stations that interconnect with New York; NYISO will need to do the same and lead to the installation of unnecessary, redundant equipment. DDR location requirements for ERCOT, Hydro-Quebec, and the Western Interconnection do not define major transmission interfaces or major transfer paths, allowing for arbitrary interpretation. Also, for the Western Interconnection, responsibility is placed on the “Regional Entity” and not a “Responsible Entity” like the Reliability Coordinator or Planning Coordinator. Comment on R6.1.5 – this will require Reliability or Planning Coordinators to call for the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in R6.1.3 (500 MW). If this requirement is retained, it should be specify “… HVDC facilities greater than 500 MW…” Comment on R6.1.6 – This requirement could lead to installation of DDRs at many, many substations in New England just to capture one flow or voltage that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. General comment on 6.1.3 through 6.1.7: The level of detail specified in these items eliminates the role of the RC/PC who are best able to determine appropriate locations for DDRs. This requirement should recommend locations and not attempt to precisely specify where DDRs should be installed. These requirements could be rephrases as follows: “The RC/PC shall specify DDR locations that serve the Purpose of this standard (To have adequate data available to facilitate event analysis of BES disturbances). The RC/PC should consider specifying locations that include generators and HVDC facilities greater than 500 MW, major transmission interfaces, transfer paths, flowgates, voltage sensitive areas…”
No
The VSL for R6 calls for the Reliability Coordinator or Planning Coordinator to have “accurately identified the Elements for DDR as directed by Requirement R6”. The term “accurately” should be deleted.
No
Installation of potentially 200 additional DDRs will take far longer than the time specified in the Implementation Plan.
Requirement R5.1 currently reads: 5.1. A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. Comment R5.1 – the two bullet items in this requirement are confusing/conflicting and should be reworded to clarify what is intended. I.E. is it 50 cycles per bullet 1 or three cycles per bullet 2? This is probably for single and multiple records but the language should identify the difference as shown below. • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. (Single Record Only) • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. (Multiple Records Only) Comment on R13, this requirement could place the Reliability Coordinator/Planning Coordinator in the middle of data sharing. This requirement should encourage direct sharing of data. Also, R13.3 and Attachment 2 attempts to define yet another format for SOE data; There are well established formats for this type of data, such as COMTRADE, that include many other aspects of data such as file and signal naming conventions.
Individual
David Kiguel
N/A
No

The proposed definition of SOER indicates that it may include protection and control devices. However, R3 only specifies the recording of circuit breaker position (open/close). The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances." In order to permit for a comprehensive analysis of disturbances some basic protection device information is necessary and should not be optional in the definition. I suggest replacing "may include" with "includes."
Yes
No
1. Requirement R6.1.5 – Consideration should be given to address the case when the ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter are owned by different entities 2. Requirement R6.1.6 – Justification should be provided on the technical justification for all Elements associated with IROLs to be monitored. The NERC lists including all elements associated with IROLs are very extensive, thus significantly increasing the number of the DDRs that need to be installed.
Yes
Yes
The Drafting Team and NERC staff are to be commended for the work done, this being such a complex standard. They have taken the right approach by addressesing "what" (data) is to be captured, not "how" and by not considering Disturbance Monitoring equipment. However,additional work is needed to make this standard acceptable. 1. The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 should be to identify busses for DME, expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO and notify such identification for the Elements owned by others, if any. 2. R4.1- As written, this requirement could be confusing. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – "…. Voltages for each phase of either each line or bus." which could be confusing. 3. R4.2 – Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This requirement should specify that if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). 4. R4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. 5. R5.1 Bullet 2- The wording should be changed as follows: "At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder." Since the deployment of Fault Recorders is not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it occurs more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. 6. There seems to be an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. 7. Real and reactive power may not be able to be determined operationally if for example, a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing "nominal" real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. 8. R3, R4, R12, R13, R14 all reference "the bus locations as per Requirement R2" however this requirement is a notification

requirement only for Elements not owned by the TO that need DME. These requirements need to refer to both R1 and R2. 9. R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 10. R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above).
Individual
Texas Reliability Entity
Texas Reliability Entity
Yes
In the definition of Dynamic Disturbance Recording, we would suggest including phasors in the list of power system characteristics. This would be useful in applying DDRs at locations where there may be angular stability concerns or subsynchronous resonance concerns.
Yes
(1) The SDT may want to consider different short-circuit MVA levels based on the voltage or voltage class, i.e. 1500 MVA for 100-200kV, 2500 MVA for >300kV, etc. (2) To insure broader system coverage, the SDT may also want to consider including some flexibility in the location criteria in Step 8 of Attachment 1, such as substations > 200kV with 3 or more non-radial line terminals, substations < 200kV with 5 or more non-radial line terminals.
Yes
Yes
(1) The SDT should clarify the meaning of “major transmission interfaces” in 6.1.4, as this is an undefined term that will lead to considerable debate about what a “major” interface is. (2) The SDT may also want to consider applying DDRs to Elements with a known angular stability issue or subsynchronous resonance issue that does not rise to the level of an IROL.
(1) For Requirements R2-R5 at substations where there are multiple Transmission Owners, are entities allowed to use a shared FR/SOER, or is each entity individually responsible for the Elements that they own? (2) For Requirement R14, there appears to be an “or” missing following the 1st bullet, “Restore the recording ability, or”. The SDT may want to consider having the entity reporting DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements required per R7.
Group
Seattle City Light
Paul Haase
Seattle City Light appreciates the effort of the drafting team in developing this proposed Standand, and understand the concept to focus requirement on data requirements rather than equipment requirements. That said, Seattle does not support this draft or approach. The draft is far too complex and technical to be an effective Federal regulation, in part because it requires a slow and cubmersome process to update each time a technical specification goes out of date. Seattle recommends that the Standard be revised to provide general requirements that are consistent over time, with details referenced in a separate document similar to the data collection and data preparation manuals associated with data-collection regulations in other areas (such as for regional

model development). Additionally, Seattle cannot support such a detailed and complex Standard until additional guidance is available about the compliance implications, such as an RSAW or guidance document.
Group
Reason International, Inc.
Lucas Oliveira
Yes
No
Several problems in the correct operation of protective measures are related as reflexes of unmitigated harmonics influencing the actuation of protective relays. Industrial plants with high nonlinearities and intense electric power consumption have large influence in the interconnection to the transmission system. The harmonic distortions introduced by these industrial plants range from low to very high orders, up to the 20th harmonic. These distortions may lead to measurement errors and the incorrect operation of protective relays. To avoid aliasing the sampling rate needed to analyze such events, capturing up to the 24th harmonic, should be 48 samples per cycle. Fault recording should therefore be carried out at a minimum of 48 points per cycle, above the typically used 16 points per cycle of protection algorithms.
Yes
No
Power swings are one of the most common and dangerous long-term disturbance events. They occur due to inadequate power flow conditions in a variety of states of the BES. These dangerous states may be reached through unforeseeable manual maneuvers or inadvertent automatic maneuvers during operation, as those occurring during an fault. Power swings may evolve to a system-wide failure, due to voltage dips, under- over-frequency, etc. To correct evaluate this situation it is necessary to compute the system power. Therefore, it's also necessary to monitor currents as well as voltages.
Yes
Yes
Attachment 2 provides a template for standardization of Sequence of Event records. Following the successful implementation of COMTRADE and recognizing the leading role the US BES plays internationally, it would be more beneficial to all parties involved if the template was based on C37.239-2010 COMFEDE, avoiding multiple templates for SOE records in several countries.
Group
ACES Standards Collaborators
Ben Engelby
No
We do not support the proposed definitions because these seem to be straightforward and understandable without proposing additional glossary terms. The Standards Drafting Team Guidelines, dated April 2009, states: “The SDT should avoid developing new definitions unless absolutely necessary. There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the

phrase rather than trying to obtain stakeholder consensus on the new term." We do not see how these proposed terms are "absolutely necessary." Please provide a rationale why other approaches could not be taken.
No
We concur with the drafting team's observation and rationale that there is no need to monitor disturbances for small systems in the same manner as large systems. However, we believe this standard should require an entity to generate its own methodology that identifies how it will determine locations to install Fault Recording and Sequence of Events Recording devices and supporting equipment and how often it will conduct these assessments. We feel the method proposed for selecting bus locations is too restrictive and could be subject to interpretation from auditors when not properly followed.
No
(1) There is confusion over the Planning Coordinator and Reliability Coordinator functions and their respective relationships. As the standard is currently written, both the PC and the RC are subject to the standard in ERCOT? (2) We do not believe any function would benefit from the standard. Industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types financial incentives to continue installing PMUs for situational awareness. The existing financial incentives have obviated the need for the standard as evidenced by report on the September 8, 2011 Arizona-California outages. There was sufficient data to analyze the event. NERC should develop a technical guideline on this topic instead of a standard.
No
We believe that Requirement R6 could be consolidated with other requirements and the detailed sub-requirements could be moved to an appendix. This would be more appropriate to model this standard like PRC-023-2, where the appendix provides important details but does not subject registered entities to violations for every sub-requirement.
No
We do not support the standard as written, as it should be consolidated into fewer requirements and should take a more streamlined approach. Since we do not support the standard, we cannot support the corresponding VRFs and VSLs.
No
The implementation plan is confusing. We do not see the need for a phased in plan, where some requirements are enforceable before others. Assuming standard continues to be developed which we do not support, we recommend consolidating the entire standard to two or three requirements and propose a straight forward implementation plan.
(1) This standard is unnecessary because there are already significant amounts of PMU data to construct sequence of events and other post-event analysis of disturbances. As referenced in the Southwest Blackout Report of 2011, there is a multitude of disturbance monitoring devices installed on the electric grid. The Southwest Blackout Report states, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." We do not see the cost benefit of requiring additional resources for an issue that is not a high priority for reliability. (2) As stated above, there are financial incentive programs through other federal agencies that provide funding for disturbance monitoring equipment. We recommend that NERC work with those programs to develop a technical guideline to ensure these devices are installed and monitoring critical areas of the electric system. (3) Why has the drafting team decided to include 14 requirements to this project? In light of recent standards projects like Paragraph 81, the industry is supporting reducing and consolidating the amount of requirements. We do not see the need to have 14 requirements for disturbance monitoring. While we do not believe the standard is needed, we strongly recommend that the drafting team revise this standard to two or three requirements if it persists. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. (4) R2 requires implementation within ninety days of Fault Recording and Sequence of Events Recording devices following a notification provided by the Transmission Owner. We question if this will provide entities sufficient time to acquire such devices from their suppliers. Moreover, entities can be, from time-to-time, directed to suspend maintenance activities on their BES elements due to extreme weather conditions or more immediate system level emergencies. These entities plan their maintenance activities months in advance, only to have such activities delayed by days or weeks as necessary to maintain system reliability. We recommend

extending the period required within R2 to at least twelve months, as this should be sufficient time to acquire and install these recording devices during non-peak calendar dates. (5) We feel that R8 and R9 do not adequately accommodate joint substation facilities and shared resources. As stated, the burden to install Dynamic Disturbance Recording devices falls on each individual Transmission Owner and Generator Owner. Sharing such installations limits the number of connected measuring devices to facility structures, including current and potential transformers, further limiting the possibility that one of these measuring devices catastrophically fails and leads to a more significant impact on the facility's availability because they are jointly owned. (6) We previously commented that an appendix, modeled similarly like in Standard PRC-023-2, would be a better alternative to Requirement R6. Likewise, including details like those listed in R12 would further strengthen a case to incorporate this appendix in the Standard and not subject registered entities to possible violations for every requirement. We feel that technology has significantly improved since 2003, as manufacturers have supported the need to align such devices on a common frame of time. Still R12 places the burden on registered entity, when it seems more appropriate to be included in a manufacturer technical specification. (7) We feel Requirement R13 is arbitrary, could be subject to interpretation from auditors and meets paragraph 81 criteria. Transmission Owners and Generator Owners could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their Reliability Coordinators, Regional Entities, and NERC. Furthermore, this standard meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. The requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. Please strike the requirement in its entirety. It would be more appropriate to include in a guideline. (8) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. For instance, we feel requirements R1.2 and R6.2 are "Periodic Updates" due to the need to reassess each list every five calendar years. Likewise, we feel requirements R2, R7, and R13 are "Administrative" due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be "Data Collection" in nature. Requirements R5.1, R5.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R10.1 and R10.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R11.1 and R11.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R12 require the collection of data according to specifications outlined for time synchronization. Finally, Requirement R14 is "Administrative" and "Documentation" in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (9) The costs of installing new equipment for disturbance monitoring could be significant for our members. We find this standard is unnecessary and NERC should work with the Department of Energy (DOE) to further expand the use of grant money to supply registered entities with funding for these types of monitoring equipment. The prior grants from the DOE have been very successful and we see no reason to require these monitoring devices to be subject to enforceable reliability standards. There is no convincing evidence that these standards are being developed to address a reliability need. We see no justification for industry to allocate resources to disturbance monitoring equipment when there are other priorities that should be addressed first, such as cyber security. Furthermore, the joint NERC and FERC report on the September 8, 2011 outage in Arizona and southern California further demonstrates that there is not a need for the standard. It stated that there was ample event data that was recorded and used to analyze the event. (10) We appreciate the opportunity to comment on the cost of developing this standard (CEAP process). However, the timeline of submitting comments should align with the ballot and comment deadlines. It is unreasonable to set the comment deadline for the CEAP two weeks before the project comment deadline, considering the due date is Monday following Thanksgiving. We are concerned that industry was not aware of this deadline and did not have adequate time to prepare comments. (11) Thank you for the opportunity to comment.
Individual
Shirley Mayadewi

Manitoba Hydro
Yes
No
The intent of the methodology is good and will help TOs in determining the number of DMEs required. However, the application of the methodology using the provided "Median_Method_Template” is quite cumbersome and could be simplified.
Yes
Yes
Yes
No
The times for meeting requirements R1 and R6 are adequate. However, the time of 9 months required for complying with requirements R2, R7 and R14 is too short, especially considering that R14 may require troubleshooting, testing, shipping, repairs, possible replacement of the failed FR, SOER or DDR, possible discussions with suppliers, design and drawing considerations if the replacement is not identical, etc. Given the existing demands on maintenance and design staff, and the need to also develop a corrective action plan for the Regional Entity, the SDT should consider extending this time.
(1) An acronym is given for each of Sequence of Events Recording (SOER) and Fault Recording (FR) and Dynamic Disturbance Recording (DDR) but the acronyms are never used, and sometimes the full phrase is used without the acronym noted. This occurs throughout the standard and should be made consistent and cleaned up. If the acronyms are not going to be used, there is no need to state them. (2) R1, 1.2 - would be clearer to state 'identified bus locations should be reassessed at least once every five calendar years’. (3) M1 (same applies for all measures) - should be written to say that the entity 'shall have' not 'has'. (4) M1 - the last few words of the measure that deal with 1.2 are not complete - 'assessed within the required interval' should be 'and evidence that the identified bus locations have been reassessed within the required interval'. (5) R2 - would be more consistent with the rest of the standard to refer to 'BES bus locations' rather than 'locations' and 'identified' instead of 'established' and 'identification' instead of 'determination'. (6) M2 - would be more consistent to say 'BES Elements' rather than just 'Elements' and 'at the BES bus locations identified' as opposed to 'established' and 'notice' instead of 'information'. The measure is also missing the timeframe. (7) R3/M3/R4 - the reference to Requirement R2 does not seem correct in this context - should be those BES bus locations identified in R1? (8) M3 - the description of the circuit breaker position in M3 is lacking specificity that appears in requirement - '(open/close) for each.....' (9) R4 - for consistency, 'bus locations' should be 'BES bus location' and 'as per' should be 'identified in'. (10) R6, 6.2 - would be clearer to state 'the identified BES Elements shall be reassessed at least once every five calendar years'. (11) M6 - would be more complete to state 'The Responsible Entity shall have a dated (electronic or hard copy) list of BES Elements for which Dynamic Disturbance Recording (DDR) is required as identified in accordance with Requirement R6 and evidence that such identified BES Elements have been reassessed within the required interval.' (12) R7 - reference to 'the locations' needs to be more specific - is this the 'BES bus locations'? To be consistent, 'Elements' should be 'BES Elements' and 'established in' should be 'identified in'. (13) M7 - would be clearer if reference to 'owners' was to 'each Transmission Owner and Generator Owner'. 'established' should be 'identified' to be consistent. (14) R8 - 'Element' should be 'BES Element'. The words 'for which they received notification' could be added after 'own'. (15) R9 - same comments as R8 (16) R10 - the reference to R7 does not seem correct - is this meant to be R8 or R9 as it is these parts that put obligation on the TO and GO, whereas R7 puts an obligation on a responsible entity? Reference to 'equipment' seems vague - is this DDR equipment? (17) M10 - reference to 'data recording' should be to DDR? (18) R11 - as above, the reference to R7 does not seem correct - should be R8 or R9? 'Element' should be 'BES Element'. (19) R12 - as above, reference to R7 should be to R8 or 9? 'Element' should be 'BES Element', 'bus locations' should be 'BES bus locations' and

the word 'identified pursuant to' should replace 'as per' to be consistent. (20) R13 - same comments as R12. (21) M13 - the words 'data was submitted' should be replaced with 'that SOER, FR and DDR data was provided to the Reliability Coordinator, Regional Entity or NERC upon request'. (22) R14 - same comments as R12.
Group
MRO NSRF
Russel Mountjoy
Yes
No
For R1 – Add wording that would only obligate each Transmission Owner to identify BES bus locations where it owns Elements with wording like, “. . . Each Transmission Owner shall identify BES bus locations where it owns Elements . . .“
Yes
Please see question 7.
No
Note that R6 clearly states where DDRs are required where the intent of this Standard was for “data” and not devices. The SDT has presented mixed signals to the industry, please clarify. In R6.1.2., it states that at least one DDR location in each Responsible Entity’s footprint. It is not clear if this means the Responsible Entities listed in R6 or the Responsible Entities listed in the Applicability Section 4. Does the Planning Coordinator or Reliability Coordinator, (as applicable) identify BES Elements for which DDR is required in the footprint of each Transmission Owner and Generator Owner or in their own respective footprints? R6.1.2. should be clarified to read “Each Planning Coordinator or Reliability Coordinator, (as applicable) is required to have at least one DDR in their footprint.”
No
According to the Implementation Plan, the STD makes it clear that this Standard reflects the need for data, not the equipment used to collect the data. In addition, the SDT has already identified that there is already a significant amount of SOER, FR, and DDR equipment currently employed on the BES. The NSRF wants to point out that Section 215 of the Federal Power Act states that the ERO cannot order the construction of additional generation or transmission assets. The NSRF views the purchasing of equipment to provide "data" as construction. The Implementation Plan states that Generator Owners and Transmission Owners may be required to schedule outages to install or implement SOER, FR, and DDR equipment. Installing or implementing of SOER, FR, and DDR equipment is construction because it changes the current equipment configuration to a different configuration. To build on this point, Requirement 12 has the requirement to synchronize the time element. We believe this can only happen with some sort of satellite clock/ gps device, requiring the purchase of said additional device.
The NSRF believes that this Standard should apply only to those devices already installed by the Generator Owners and Transmission Owners on BES Elements. The SDT has already made it clear that there is an abundance of these devices on the BES. Therefore, a footnote should be added that the Registered Entities are not required to spend the ratepayers’ money to buy new equipment to satisfy the requirements of this Standard. The NSRF proposes it should read “Each Transmission Owner and Generator Owner is not required to have Dynamic Disturbance Recording, Fault Recording, or Sequence of Events Recording devices which capture the essential data of PRC-002-2, installed or activated on its BES Elements.” This would be incredibly comparable to footnote 1 of the industry-approved NERC Standard PRC-024-1. That footnote states “Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.”

Group
Dominion
Mike Garton
Yes
We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.
Yes
Yes
Yes
However, clarity is needed under 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. Also clarity is needed in requirement 6.1.4 when you refer to “monitor all Elements of: all permanent flowgates”. If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. Also, under requirement 6.1, it may be better to move the minimum quantities requirements 6.1.1 (minimum 1 DDR per 3000m MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 does not meet the two extra minimum quantities requirements.
No
Recommend updating the “entity” for the following requirements on the Implementation Plan Summary: R8 – TO R9 – GO R10 – TO/GO
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, 2013, NPCC applicable entities are two 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 with this Regional Reliability Standard. 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. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01). Dominion believes the intent of Requirement R2 is for Transmission Owners to notify “other” owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, Dominion suggests revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the “other” owners of those Elements… M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to “other” owners of Elements… In R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis. As written, it provides no clause to prevent excessively short re-

assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…". If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. In R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say "A single record or multiple records that include at least one of the following:". In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet – "If recording ability is not restored within 90 days, report the inability..."
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes
Yes
No
We respectfully request that a methodology similar to the one that was used in R1 is deployed in this requirement in order to determine an adequate percentage of flowgates needed for visibility of faults.
No
We believe that the time frames in the violation severity levels are too stringent when compared to the other items in the same violation level. A relatively short term delay in communication (30 to 60 days) is much less severe than not performing a function. Suggest lengthening out timeframes.
Yes
(1) We feel that the first bullet of 5.1 is not needed due to the content of the second bullet. If the team determines that it does need to be kept, a post-trigger record length of 30 cycles for the same trigger point would be adequate. (2) For R14, please provide additional clarity around the fact that if the equipment is returned to service within the 90 day time limit then it does not have to be reported. Respectfully suggest the second bullet to change to, "If not returned to service within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability."
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Yes

Yes
1. In R2, to avoid confusion as to what the phrase “BES Elements at the locations established in Requirement R1” means, we recommend that the Attachment 1, Step 1 have this sentence modified with a new parenthetical phrase an the end: “A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid (i.e., Elements directly connected to the bus).” In addition, since the only owners of those Elements may be other TOs or GOs, the reference to “shall notify the owners of those Elements” should be clarified. This requirement should be written as follows: “Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the TRANSNISSION OWNERS AND GENERATION OWNERS of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR).” 2. In R10, the last two bullets should be combined into one: • Under voltage trigger set at no lower than 85% of normal operating voltage for a duration of 5 seconds. 3. The language in R14 should have “either” added to clarify the required actions. In addition, the language in the second bullet “Report the inability to record data” was changed to “Report the inability to restore the recording ability.” See below. “Each Transmission Owner and Generation Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recoding (DDR) at the bus locations per Requirement R2 and Elements as per Requirement R7, shall EITHER: • Restore the recording ability • Report the inability to restore the recording ability to the Regional Entity along with a Corrective Action plan (CAP) to restore the recording ability.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
(1) In Requirement R5.1, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (2) In Requirement R14, Seminole reasons that the requirement is intended to require the filing of a CAP if the inability to record data exists for longer than 90 consecutive calendar days. This reasoning is in line with the Rationale box for Requirement R14, however, the actual Requirement appears to require the filing of a CAP notwithstanding if the failure is remedied within 90 calendar days of discovery of the failure. Seminole requests that the requirement be revised to state that the filing of a CAP is only required if the inability to record exists for more than 90 calendar days from the date of discovery. (3) In Requirement R14, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (4) In Requirement R14, it appears that the intent of the SDT was to require the submission of a CAP if the failure was not remedied within 90 calendar days. If the failure is not remedied within 90 calendar days, it appears from the Requirements and the VRF/VSL penalty matrix that a CAP is required to be submitted to the RE within the same 90-day window. Seminole requests that the time to submit a

CAP be extended an additional 30 calendar days to read that an entity has 120 calendar days from the date of discovery of a failure in which to submit a CAP to its RE. This would allow a true 90-day window for fixing the CAP. For example, under the current language if an entity believes it will have remedied a piece of equipment on day 83, it would probably be best practice for that entity to prepare a CAP for submission in order to meet the 90-day CAP submission window in case delays arose. Seminole believes that this is not in line with the intent of the SDT and Seminole request the additional 30-day window for submission of a CAP, i.e., 120 days from date of discovery of the failure, and for Requirement R14 and the penalty matrix to reflect this change.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
Attachment 1 and the median method results in an excessive number of buses requiring disturbance monitoring for a system (a large amount of tightly interconnected buses within a metropolitan area).
Yes
No
The inclusion of all permanent flowgates is our objection. This requirement will result in the inclusion of monitoring points that are not necessarily critical to the BES. The approach of the Western Interconnection to include all major transfer paths as defined by the Regional Entity seems to be a more logical approach.
Yes
No
We do not agree based on our earlier comments in regards to Attachment 1.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration L.P. agrees with the strategy the project team has taken to focus on the output of recorders – not the devices themselves. Recording technology is rapidly evolving and equipment-related requirements may be quickly be outdated otherwise.
Yes
Ingleside Cogeneration notes that the MVA thresholds applied are generally consistent with those established in EOP-004-2 “Event Reporting” and the criticality criteria used in CIP Version 5. This makes inherent sense, and would encourage the use of similar rules across all NERC standards in order to properly balance regulatory costs against benefits.
Yes
No
Unlike the MVA thresholds applied in R1, ICLP does not believe that the 1000 MVA threshold for generation facilities (R6.1.3.2) is consistent with other NERC criticality criteria. In addition, from the perspective of a Cogeneration facility, full nameplate capacity is normally not fully available to the Bulk Electric System. Therefore, either the threshold should be raised to 1500 MVA or should be revised to specify that the 1000 MVA threshold refers to “aggregate nameplate capacity available to the BES”.
Yes

Yes
Ingleside Cogeneration L.P. believes that the two to four year deployment schedule for recording capability is sufficient.
Individual
Venona Greaff
Occidental Chemical Corporation
Agree
Ingleside Cogeneration, LP
Group
Tacoma Power
Chang Choi
No
What is the purpose of the following clause in the definition of SOER: "…which may include protection and control devices"? Since the focus of this definition is on recording, and not equipment, consider removing this clause.
No
The 1500 MVA fault level includes many busses that are relatively unimportant to the BES. For example, in the 115 kV portion of our system, 83% of buses have fault levels above 1500 MVA. On our system, fault levels of 4000 MVA are a much better indication of buss important to the overall BES. However, rather than create a new MVA criteria in this standard, we suggest using criteria developed for other standards that determine important subsets of the BES. The requirements in CIP-002-5 R2.5 define substations that have a "medium" impact on the BES. Requiring a FR at a substations classified as "low" is overly burdensome. Alternatively, substations that do not have circuits subject to PRC-023-2 applicability section 4.2.1 should be except from FR requirements. Although we already have fault recorders on all 115 kV transmission substations with more than 3 lines, the purposed methodology would require additional Fault Recorders. These additional fault recorders would provide very little additional data, because the existing fault records include the remote ends of almost all transmission lines. The proposed standard does not take into adequate account the industry progress towards GPS synchronized microprocessor based relays. Much of the data required by FR is already recorded by relays. However, relay records only count as FR if they meet all the FR requirements for the entire substation. Rather than focus on obtaining 100% coverage of quantities at substations, this standard should facilitate taking advantage as much as possible of already installed hardware.
Yes
No
Considering the VSLs for Requirement R4, using "the product of the total number of monitored BES Elements and the number of specified electrical quanitities per each Element" would work well for current on the Element, but what about bus voltage shared by DDR on multiple Elements? Considering the VSLs for Requirements R4, R5, R8, R9, and R11, would it be more appropriate to base the percentages on how many required BES bus locations or BES Elements have the minimum recording properties, electrical quantities, or other specifications/parameters? (Consider the language in the VSLs for Requirement R10.) It seems like determining a percentage of the total recording properties, electrical quantities, or other specifications/parameters may be difficult in some cases. An example (scenario) of how these VSLs, as written, would be applied may be helpful. Should the Severe VSL for Requirement R11 be written something like the following? "The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets less than or equal to 10% of the total recording properties as specified in Requirement R11." In other words, is '1%' intentional? Considering the VSLs for Requirement R13, are the percentages based upon (1) BES bus locations, or BES Elements; (2) recording properties, or electrical quantities; (3) length of data recorded; or (4) a combination? An example (scenario) of how these

VSLs, as written, would be applied may be helpful. In the VRF/VSL Justification, the FERC VSL G3 comment for Requirement R11 is missing (page 34).
No
The disagreement is not so much with the implementation plan itself but whether part of the implementation plan should reside within the standard itself. More specifically, should part of the implementation plan be included under Requirements R3, R4, R5, R8, R9, R10, R11, R12, and R13? Of primary concern are BES bus locations or BES Elements that are added as part of the review at least once every five calendar years. An implementation plan normally addresses phasing in of the standard, or new version of the standard, not ongoing implementation.
There is general concern about the cost of implementation, especially cost sharing for installation of Dynamic Disturbance Recording (DDR). For example, the Responsible Entity seems to have latitude on selecting BES Elements, beyond the DDR locations identified in Requirement R6, Parts 6.1.3 through 6.1.7, and therefore which Transmission Owners and Generator Owners must install DDR to meet Requirement R6, Part 6.1.1. If two Transmission Owners share equipment at a BES bus location, which Transmission Owner is responsible under R1 and R2 for identification and notification? Under Requirement R5, Part 5.1, do the bulleted items constitute an ‘and’ or ‘or’ condition? For example, if a post-trigger record length of 50 cycles is available, but a fault lasts 51 cycles such that the final cycle of the fault is not captured, would this be compliant with the intent of Requirement R5, Part 5.1? If not, then it seems that either (1) both bulleted items would be required or (2) just the second bulleted item would be required. Consider changing “a single record or multiple records that include:” to “a single record or multiple records that include at least one of the following:” Under Requirement R5, Part 5.3, what latitude are Transmission Owners and Generator Owners afforded in establishing thresholds for neutral (residual) overcurrent and phase undervoltage trigger settings? Under Requirement R6, Part 6.1.7 attempts to define every area that uses UVLS as a “Major Voltage Sensitive Area.” UVLS programs are also used to address localized voltage issues. As currently written, a DDR would be required for every entity that uses any undervoltage relays, no matter how localized. We suggest removing section 6.1.7 as the other criteria in requirement 6 will provide widespread installation of DDRs. Under Requirement R8, Part 8.2, consider changing “…same voltage corresponding to…” to “…same voltage level corresponding to…” Under Requirement R9, Part 9.4, consider changing “…of at least one of…” to “…of any of…” Under Measurement M12, consider explicitly adding “station drawings,” or similar verbiage, as evidence. Device specifications and configuration or actual data recordings may be insufficient to demonstrate time synchronization; it may be necessary to demonstrate that cabling is connected. If failure of DDR is discovered, recorded data may not be retrievable for the period of 10 calendar days preceding a request. If a disturbance occurs before recording ability is restored, but an entity is compliant with Requirement R14, is it the intent of the standard that an entity could be found non-compliant with Requirement R13 for the failed DDR? Under Measurement M13, change “…evidence (electronic or hardcopy) data…” to “…evidence (electronic or hardcopy) that data…” Under Requirement R14, does loss of time synchronization qualify as a “failure”? Generally, it seems that this type of issue would be corrected quickly (within 90 calendar days of discovery) and therefore not require reporting. Under Requirement R14, if a Transmission Owner or Generator Owner restores the recording ability within 90 calendar days of the discovery of a failure, does the failure need to be reported to the Regional Entity to be compliant with Requirement R14? In other words, do the bulleted items under Requirement R14 constitute an ‘and’ or ‘or’ condition? In Attachment 1, Step 1, would bus Elements on the high-side of transformation at the same physical location be considered a single bus location and be distinct from the bus Elements on the low-side of the transformation, even if both sets of bus Elements share a common ground grid? In other words, is it possible to have two bus locations at the same physical location, even if they share a common ground grid, provided that there is transformation connecting the two bus locations? Consider a 230kV to 115kV substation. In Attachment 1, Step 1, what is meant by the verbiage “…or from other DME devices”? Additionally, the acronym ‘DME’ does not appear to be defined in the standard itself (only in the Rationale for R14).
Individual
Luminant Energy Company LLC
Luminant Energy Company LLC
Agree

Luminant Generation Company LLC
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
No
The methodology is acceptable, but a requirement should be added before R1 and the present R1 should be modified as noted below. a. Generator Owners should also be obligated to identify applicable bus locations where they own Elements using the Attachment 1 Steps, rather than delegating this obligation to the Transmission Owners. b. Generator Owners will be able to determine maximum available calculated three phase short circuit MVA after PRC-027-1 becomes a mandatory standard because this standard will require Transmission Owners to provide short circuit study information which makes this possible. In the implementation plan for this standard, Generator Owners could be exempt from compliance with R1 until after the applicable regulatory approvals of PRC-027-1. c. In addition, the scope of the bus locations that need to be considered for identification should be explicitly limited to locations where an entity owns Elements. d. Consider wording for the present R1, but new Requirement R2 like, “Each Generator Owner and Transmission Owner shall identify BES bus locations where it owns Elements for Sequence of Events . . .”
Yes
Yes
The criteria for selecting Elements requiring DDR in Requirement R6 are mostly acceptable. However, ATC recommends the consideration of the following wording changes: a. For R6 – Simplify the beginning with wording like, “Each Planning Coordinator or Reliability Coordinator (as applicable) shall . . .” b. For R6.1 – Specify more clearly that R6.1 is limited to BES Elements with wording like, “The BES Elements shall include the following:” c. For R6.1.1 – Make each sub requirement consistent with the parent R6.1 subject of “Elements” with wording like, “Elements at a minimum of one DDR location per . . .” d. For R6.1.2 – Make each sub requirement consistent with the parent R6.1 subject of “Elements” with wording like, “Elements at a minimum of one DDR location in . . .” e. For R6.1.3 – Add more clarity regarding the applicable Elements with wording like, “Elements at DDR locations, which interconnect the following generation resources to BES transmission buses:” f. For R6.1.4 – Make each sub item consistent with the parent R6.1 subject of “Elements” with wording like, “Elements necessary to monitor the following items:” g. For R6.1.4, bullet item 1 – Limit the scope of this item to only major permanent flowgates (similar to the other three bullets), rather than all permanent flowgates (which generally includes all BES circuits), and allow the Planning Coordinators to define what “major” means with wording like, “Eastern Interconnection – all major permanent Flowgates as defined by the applicable Planning Coordinator.”
Yes
ATC recommends the following: a. Regarding Requirement R2 – Similar to the recommendation for R1, Generator Owners, not just Transmission Owners, should be obligated to identify Elements at BES bus locations established in R1 that require SOER and FR. If any identified Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners. ATC recommends revising the R2 wording to, “Each Generator Owner and Transmission Owner shall identify which BES Elements require SOER and FR at the BES bus locations established in Requirement R1.” Revise the R2.1 wording to, “Each Generator Owner and Transmission Owner shall determine whether any required Elements are owned by other Generator Owners or Transmission Owners.” And finally, revise the R2.2 wording to, “If any required Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners of those Elements.” b. Regarding Requirement R3 – This requirement should follow through with the obligations that were prepared for in R2 by requiring SOER and FR for all of the Elements identified in R2, not just selected circuit

breakers. ATC recommends revising the R3 wording to, “Each Generator Owner and Transmission Owner shall have SOER and FR for each Element that they own and was identified per Requirement R2.”
Group
Nebraska Public Power District (NPPD)
Cole Brodine
Yes
No
For step 1 in Attachment 1 please confirm the following: For a 115kV and a 345kV bus in the same substation on the same ground grid is this considered two bus locations such that these would be used in step 3 as two of the 11 buses to calculate the median? For step 7 in Attachment 1 if I have a 230kV bus and a 345kV bus in the same substation in my top 10% is this acceptable to count them as two buses that require FR/SOER since it is a single location? Is this indicating that both buses need to meet the FR/SOER requirements? Please clarify for Attachment 1: Should a 115kV tap substation with no breakers but only a load serving transformer with a high side breaker be included in the fault bus list? It appears they should but would a tap sub with no breakers be required to have FR or SOER? Should generator GSU 13.8kV buses and tie transformer tertiary 13.8kV buses be in the bus fault list? Example list 1 appeared to have some 13.2kV buses but the instructions do say to use 100kV and above. Please confirm only 100kV or above buses should be used.
Yes
No
For clarification, “A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Demand, inclusive of Requirement R6, Part 6.1, Sub-parts 6.1.2 – 6.1.7” means that for a peak demand of 3030MW a Responsible Entity must have at least two DDRs on its system and this requirement is satisfied if two DDRs are already on the system due to the other sub parts in R6? Has or should it be confirmed the RC or PCs have a clear understanding and listing of “permanent Flowgates” and locations necessary to monitor all Elements associated with IROLs? They may need to confirm they are using similar or same terminology.
No
“directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation…” I recommend these be moved to Moderate levels if not lower to match the criteria.
No
It is recommended to have 5 years to become compliant instead of 4 years to match this with the reassessment activities. Since there is no method to track the various percent compliant for the 2nd and 3rd years it is recommended to require 100% compliance by the final year.
For clarification on R2 after receiving notification from a TO that FR or SOER may be required how long does the receiving entity have to install the appropriate recording device? Please clarify if it is still 4 years to be 100% compliant? R3 can we clarify the circuit breakers that are not connected to lines and transformers designated in R4 are not required to be part of the SOER? For example, do not require SOER for a 115kV circuit breaker on a 115/34.5kV load serving transformer. R4 M4 states that “Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.” For individual relays used as recorders this may encompass a significant amount of data. Consider allowing evidence to be a single design standard or common general design example to be allowed as evidence rather than requiring all the detail data from every location which could be hundreds of relays with settings/drawings/records for example. There is a similar concern for R3 M3 evidence. R5 5.1 states: A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. Consider using 30 cycles instead of 50 cycles for post records since faults typically should be clearing faster (less than 10 cycles on most critical high voltage lines). This may reduce the risk of memory record overwrite

in relays that are of older vintage. DDR capabilities will also most likely be installed in the most critical areas for longer recording needs. R5 5.3.2 lists a required trigger setting for phase under voltage. 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 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. I strongly recommend allowing phase under voltage or phase distance reaches for 5.3.2 as trigger points. Generally the trigger requirements appear logical. There is some concern that these recording devices are not perfect and devices that appear to be functioning correctly will occasionally not trigger as set. These are not perfect devices. Is there a risk for non-compliance for devices that are set to meet compliance yet do not trigger correctly? This seems like an unnecessary risk. R8 8.1 seems to be a bit confusing. R8 8.1 allows a single phase to neutral voltage yet 8.3 appears to require all voltages. R8 8.2 is also similar in nature. Can this be changed to require one voltage and one current on the same phase? R11 states “11.2. Output recording rate of electrical quantities of at least 30 times per second.” Please clarify to make sure this can be clearly understood by an audit or enforcement team as well as owners. Is this processing speed or DSP of a device? For example some relays state “AC voltage and current inputs 8000 samples per second, 3 dB low-pass analog filter cut-off frequency of 3000 Hz” or “protection and control processing 8 times per power system cycle”. Are these examples what is asked for with 11.2? Most devices are likely to meet this rate. Does it really need to be in the standard? This seems excessive. Any options to reduce the requirements in this standard would help to limit the complexity and data to manage. R13 states: “13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.” This is a good goal to shoot far however data can be overwritten in relaying devices with the best intentions when numerous operations and voltage levels are used to trigger events. I don’t feel that the ability to guarantee data is available for this time period is fully under the control of the person setting the pickup and triggering in the device 100% of the time. This should not be a finable enforceable requirement and should be removed. On occasion failing equipment can provide such great amounts of data as to overwrite memories in relaying equipment. R13.4 states “Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.” Can the statement be added that if the device is not capable of providing COMTRADE files directly then it is acceptable to provide the data in its native format? I am concerned with the need to reformat data could risk loss of data before it may ever get to an analysis team. Some formats may not be easily convertible in older devices. Consider adding: Data content requirements and guidelines shall be in accordance with R13.3, R13.4 and R13.5 or other formats deemed acceptable by the requesting regional entity. R14 requires the tracking of recording failures and restoration. I recommend this only be required for recording devices not under another maintenance plan. For protective relays performing recording functions they should not be under this requirement if they are covered under PRC-005 which is a stringent maintenance plan that will be in place. This will reduce additional tracking requirements and burden.
Group
JEA
Tom McElhinney
No
The 1500 MVA selection criteria is too low. It needs to be substantially increased.
Yes
It is unclear if both of the two statements in R5.5.1 are required, or if meeting only one of the two is sufficient.
Group
PPL NERC Registered Affiliates

Brent Ingebrigtson
Yes
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and 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. The TOs have the system specific knowledge as to where on their networks, SOERs, FRs and DDRs should be installed to effectively capture disturbance data. Many TOs have existing DME equipment in place (previously specified per the Regional Entities) which provides the relevant system disturbance data required for disturbance analysis. The R1, R6 requirements may lead to installation of redundant equipment. Perhaps the R1, R6 requirements should specify that the TOs evaluate where SOERs and FRs are to be installed to effectively capture disturbance data? Re-specifying DME installation per PRC-002-2 may result in redundant evaluation and equipment installation of DMEs. Previous electric sector DME efforts driven by PRC-002-1 and Regional Criteria should be recognized in the specifications for DME installations.
No
PPL made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; stand alone GOs do not. The webinar presenters stated that making R9 pertain to TOs rather than GOs would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. PPL disagrees in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of ’03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO’s system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs.-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach webex meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don’t understand.
Yes
Yes
No
Since there has been previous DME installation guidance provided by Regional efforts (via a Regional Standards or Criteria), it should be assumed that TOs have previously installed DME (SOER, FR, DDRs) equipment in locations specified per the Regional or local requirements. Therefore, requiring TOs to have any new DMEs installed per R1, R6 within 6-9 months of when PRC-002-2 becomes enforceable is not justifiable. There should be a (12-24 month) grace period to install any newly required DMEs (SOERs, FRS, DDRs) per PRC-002-2 R1 and R6. Concur with implementation time frames of R2, R7 and R14 requirements.
1. It appeared from the 11/19/13 webinar that the R9 obligation for GOs to “have” DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that “This standard defines the ‘what’ of DDR, not the ‘how.’ GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO.” It would be still better

to just eliminate GOs from the requirement, however, per our comment to question #3 above. 2. R6 sets DDR applicability criteria based on the “nameplate rating,” but doesn’t say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, “Facility Rating,” as defined in FAC-008 should then be used to avoid confusion. 3. The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent inadvertent triggering of the DME. We suggest three cycles. 4. R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/-10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. 5. Triggered (as opposed to continuously-recording) DME needs to have sufficient storage capability to capture a major disturbance and a potentially large number of aftershocks, but we have no way of knowing how many such recordable events may occur, creating a compliance risk. The SDT should establish the expected maximum number of recordable events and state it in the standard.
Group
New York Power Authority
Saul Rojas
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances”. We don’t see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
No
The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add “discretionary” stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station’s fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,…). The term “bus” can be defined in different ways, so can “location.”
Yes
No
R6.1.6 – This requirement could lead to unnecessary installation of DDRs in non-integral substations.
Yes
Yes
R10 It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? R13.3 There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2).. R13.4 This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. Attachment 2 The format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs.

R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Group
IRC Standards Reveiw Committee
Charles Yeung
Yes
No
We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the “list of BES bus locations that it owns” depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that is the case, then Step 1 in Attachment 1 needs to be clarified to distinguish the need for R1 and R2.
No
This is a “fill in the blank” as identified in the FERC Order 693 and was written to be complied with by the RROs for years. We question why there is need for the RC and PC to comply with these. In fact, the Paragraph 81 activities have identified many requirements that are by the FERC’s perspective not consequential or primary for reliability. We do not believe that a mere reassignment from the old RRO entities to the RC or PC that these requirements suddenly become critical to reliability. NERC should consider other avenues to provide entities with methods to acquire fault data for event analysis. The solution to everything we do shouldn’t be a standard. In fact nearly all new relays and digital meters have disturbance recording capabilities, it is possible to acquire data for event analysis without DDR. Since the intent of this standard is primarily to have post-event data available, it can be argued this is not a critical reliability standard. We point out that the NERC Rules of Procedure have a detailed section on disturbance response procedures.
No
R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would clarify for compliance if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6).Also, M6 for R6 states that the responsible entity must “accurately” identify elements requiring DDR per numerous sub-requirements under R.6.1. and measures degrees of compliance against an identified set of points as specified per 6.1.4. R.6.2. requires that entities, at a minimum, perform a new assessment for DDR locations every 5 years. When there are elements added to the Interconnections or long-term system reconfigurations that take a DDR(s) out of service or renders them incapable of recording the required data, should that be a trigger for a reassessment?
No
Yes
Individual
David Jendras
Ameren

No
(1) Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all.
Yes
No
(1) We ask the SDT to replace ‘Planning Coordinator’ with ‘Regional Entity’ in 4.1.1 because the Regional Entity has a wider view, and it promotes consistency.
No
(1) In conjunction with our Planning Coordinator we have voluntarily installed over 30 PMUs which was a significant effort and resource commitment over the last 3 years. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. However, if we would still need to have a PMU covering every generator with 500 MW or greater as in 6.1.3.1, as well as all permanent flowgates, as covered in 6.1.4, that would require us to add many more PMUs to the system. We believe this would be burdensome, given the effort already undertaken over the last 3 years to get to where we presently are. We respectfully disagree with the drafting team’s brief justification in the Rationale for R6.
Yes
No
We request the SDT to make the following changes: (1) Add 1 month to item 3 for the TO to identify BES Elements in R1. (2) Delete ‘bus locations and’ in item 6 so that the total percentage (%) is based on BES Elements throughout the Implementation Plan. There are bus locations at which there are several different owners of the BES Elements. (3) Replace ’24 months or more’ with ‘up to 60 months’ in item 9. (4) The Implementation Plan Summary is very helpful but the Entity is incorrect for R8, R9, and R10.
We request the SDT to make the following changes: (1) In R1, add ‘After identifying BES bus locations, each TO shall identify the BES Elements directly connected to that bus location at its voltage level.’ We request allocating another month to do so. We believe that this will provide a consistent reference for R2 which refers to BES Elements as if they’ve been established in R1. (2) In R3, insert ‘Transmission Owner’ before ‘bus locations’ to make it consistent with the page 32 Guideline for R3 explanation that the GO does not need SOER at its GO bus locations. Also insert ‘BES’ between ‘each’ and ‘circuit breaker’ because not all breakers are BES Elements. It then states ‘Each Transmission Owner and Generator Owner shall have Sequence of Events Recording (SOER) for circuit breaker position (open/close) for each BES circuit breaker they own connected to the Transmission Owner bus locations as per Requirement R2.’ (3) Include the BES bus location along with the BES Element in R6 so that it is clear that DDR is only required at one terminal of a two-terminal Element. (4) Reword R8 and R9 to ‘Each Transmission (Generation) Owner shall have Dynamic Disturbance Recording (DDR), for each location and Element as dictated by the Responsible Entity per Requirement R7, to determine…’ (5) Reword R11 to be similar using ‘that is responsible for’ to R10 to ‘Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording (DDR) as per Requirement R7 shall conform …’ (6) Reword R12 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall time synchronize data to within …’ (7) If at all possible we would like another opportunity to provide comments on CEAP for PRC-002-2 in the next draft. Several aspects of this draft made in unclear as to what is required, and therefore difficult to assess cost impact.
Individual
Chris Scanlon
Exelon Companies
Yes

Yes
We agree but, consider the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the drafting team should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn't need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
Yes
No
We believe the drafting team has done a good job of trying to focus on the important BES elements that should require Dynamic Disturbance Recording. Requiring DDR for the most important BES elements rather than all BES elements at a certain station is technically sound and a major improvement over some attempts at past criteria to determine which elements should require DDR. We concerend however that about the specificty for determination as to the number and location of where DDR will be required per this requirement. The requirment may result in an unnecessary number of installations. We urge the drafting team to provide for the PC to determine the number and location of the devices. Addtionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
No
We don't agree that R3 is necessary at all, see item 7 comments. In a large company hundreds of pieces of equipment require monitoring. If one item out of hundreds are missing, the effect on monitoring is minimal. The drafting team should consider changing the lower violation severity level to more than X% but less than 95% (instead of 100%). Zero tolerance approaches, especially on standards that "look back" and support analysis are unnecessary and wasteful of engineering resources.
Yes
Comments on R3: R3 states that circuit breaker position must be monitored for identified breakers. In our companies standard design, we connect circuit breaker auxiliary contacts to relays that include monitoring. However, this requirement will present a significant burden since a database must be created to cross-reference prints to prove that hundreds of breaker auxiliary contacts are connected to satisfy compliance requirements. Since three phase currents are to be monitored under the proposed Requirement3, this information can be used to determine circuit breaker status in lieu of monitoring a 52 contact. With three phase current values available, it is not difficult to figure out when breakers were opened based on loss of current and is actually more accurate than breaker auxiliary contacts. It is very straight forward to figure out when breakers are opened based on loss of current for a straight bus configuration. If a single circuit breaker in a ring bus or similar configuration opens for some reason and flow is not interrupted the sequence of breaker openings can still be determined using currents. It is also not necessary to know exactly when a breaker in a ring bus opens if flows in the ring are merely rerouted. Thus, a detailed sequence of events timeline of a power system disturbance can be determined without the use of a circuit breaker contact. In rare cases connection of a circuit breaker contact may have been mistakenly excluded from the

protection design. In this case, complying with the standard as written could require installing 1000 feet or more of control cable in an EHV switchyard, incurring a high cost for very little gain. Thus, we believe the drafting team should eliminate this requirement as it just creates a significant burden, potentially adds cost, provides no commensurate increase in reliability, and is not necessary for events analysis when three phase currents are already required. Comments on R4: It is a natural progression for a TO to upgrade BES lines before upgrading BES transformers since BES lines are subject to many more faults and operations. Thus, modernizing BES lines first has the greatest impact on reliability. For example, a large % of our comapies T-lines employ modern relays with FR and SOER capability and the remaining lines will have this capability shortly. These upgrades are being done on previously determined schedules and include all 138 kV and above lines. The percentage of BES Transformers with modern equipment is much less (15-20%) and upgrades are typically only done when transformers infrequently fail or when protective equipment is obsolete and problematic. Although R4 does state that the TO/GO shall have fault recording necessary to determine required quantities (transformer information can be determined from monitored line data as needed), the drafting team should consider revising the guidance section of R4 to state that it is adequate to monitor lines and use their fault recordings to determine transformer quantities. The drafting team should also consider just eliminating R4.2.1. Monitoring lines is much more important and provides information to determine flows in transformers. This would also recognize that the natural progression of system upgrades is to concentrate on the most exposed and problematic areas (T-lines). The number of transformers with increased monitoring is increasing sufficiently already and monitoring of transformers inherently benefits from the rapidly increasing level of monitoring on transmission lines. Comments on R5: R5.3 states that trigger settings need to include Neutral (residual) overcurrent and phase undervoltage. RFC had a disturbance monitoring standard for a few years that we worked diligently to comply with. It required triggering on one or more of various quantities including negative sequence current, negative sequence voltage, residual current, undervoltage, overvoltage, or overcurrent. ComEd met this requirement in hundreds of devices by triggering on residual current (for grd faults), phase overcurrent (for multi-phase faults), and pickup of any forward or backward (if used) phase distance zone (for multi-phase faults). Undervoltage elements weren't always available. The drafting team should consider modifying this requirement to allow phase undervoltage or phase overcurrent as a trigger for multi-phase faults. Having to tweak hundreds of relay settings (an arduous and expensive process) to meet a NERC standard that is slightly different than the RFC standard just doesn't seem right. There is a good argument that once a system is highly monitored, triggering an event record when the relay trips provides sufficient information for events analysis. We do not believe that a standard specifying what to trigger on is necessary at all for a highly monitored system. Having to go back and change event trigger equations on a highly monitored system is purely burden to the registered entity with no commensurate increase in reliability or increased capability to analyze disturbances.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
No
Please see the comments of the NAGF SRT. I support their response to this question.
No
Generator should not be a functional entity for this standard. In cases where generators own a breaker on a transmission system, the only requirement should be a breaker status signal, which properly should be supplied under the interconnection agreement.
No
The standard is too prescriptive for DDR. The TO should select the sites, install and maintain the DDR they properly need to analyze a disturbance on their system. The standard should simply require "DDR shall be installed as necessary to analyze a fault on the TO's system". Violations of the standard would only occur if a fault is unable to be analyzed due to equipment not being installed (not due to failure or outage of installed equipment).

No
No
See the NAGF SRT comments. Smaller entities who may have one SOE system to install will be forced to comply 100% within two years.
See NAGF SRT comments.
Group
Corporate Compliance/Engineering
Ed Croft
Yes
No
The document "Mapping of Standard's Introduction of BOT Approved PRC-002-1 to Proposed PRC-002-2" from January 2013 described line terminals above 200 kV and large generators/transmission stations which warrant this level of data gathering, as they represent the backbone of the transmission system. It would be better to start with this system level first and test out data collection. For the sake of comparison, the approximate median value of the 11 highest (short circuit) MVA PSE buses where digital fault recorders are already in place, is 6800 MVA. Lowering to a short circuit MVA level of 1500-2500 MVA quadruples the quantity of collection sites.
Yes
Yes
No
Referring to comments for Question 2 on this Comment Form, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for a time. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
No
Referring to comments to Question 2, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for 2-3 years. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
Group
Florida Municipal Power Agency
Frank Gaffney
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.

FMPA does not believe that a standard is justified for Disturbance Monitoring, as such, we believe that disturbance monitoring is better addressed through guidelines than through a standard, as further discussed below. In the scheme of things, disturbance monitoring provides very little value to operating the bulk-power system reliably as compared to other standards. Establishing SOLs and operating to them; coordinating and maintaining effective protection systems; maintaining supply/demand balance and frequency; cyber security; and effective and trained human resources are greater than one quantum step more important to reliable operations than equipment installed simply to ease the ability to perform post-mortem analyses on events and to validate stability modeling that cannot be that accurate in the first place simply due to Chaos Theory (e.g., the Butterfly Effect) and the inability to predict the future accurately. While installing DMEs may be good / prudent action, FMPA believes it is imperative to avoid a mode of thought that seems to prevail among many within our industry, and that is a mode of thought that if something is good for reliability, then we need to write a standard for it. Such mode of thought is counterproductive and stunts creative improvement because it creates a perverse incentive to only do the minimum to meet the existing standards due to the danger of better performance causing an increased level of governmental regulation. Governmental regulation should be to minimum requirements while not stunting the creativity of the industry to perform better than required, and FPA Section 215 is crafted with that thought in mind: "The term `bulk-power system' means-- `(A) facilities and control systems NECESSARY FOR OPERATING an interconnected electric energy transmission network ..." (emphasis added) "The term `reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system." While DMEs may be good/prudent, they are not necessary to provide reliable operation of the bulk-power system. In addition to a lack of technical justification, a standard that requires DMEs is also not justified from a cost/benefit perspective. The benefit of DMEs as stated in the purpose of the draft standard are to assist in post-mortem analyses of events. We have been doing event analyses for decades without the standard. Yes, they may take longer to perform do to the difficulty in establishing a sequence of events post-mortem and other challenges, but, we were able to do it. So, the benefit of a DME is to shorten the time and effort it takes to do a post-mortem (what is that, maybe three or four person-years, maybe a million?) compared to a cost of installing these devices and maintaining them on hundreds of buses (maybe $10's of millions) for events that may happen once in 10-20 years close enough to a DME to matter. In addition, the system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays prevalent throughout the system and phaser measurement units (PMUs) also installed throughout the system. Additionally, the effort does not justify the compliance administration costs at both the entities and at NERC and the Regions for administering compliance to this proposed standard. The standard as written is complicated, long, has many requirements, and in general is far too complicated and onerous in relation to its minimal reliability benefit. Also, how would such a proposed standard impact compliance with PRC-006, EOP-004 and other standards that require post-mortem event analyses? In conclusion, FMPA believes that a standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Individual
Oliver Burke
Entergy Services, Inc.
No
1) Add “balanced three phase” between “dynamic” and “power” in order to clarify the context of Dynamic Disturbance Recording. The revised definition would be “The recording of time sequenced data for dynamic, balanced three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.” 2) The definition of SOER presently uses the phrase “... status of Elements, which may include protection and control devices.” Recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also, the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3) Recommend not using the acronyms SOER, FR, and DDR as defined NERC Glossary acronyms. These acronyms have historically been

used by industry to label the recording equipment; therefore the same acronym should not be used when referring to the equipment's data.
Yes
Yes
No
We believe the proposed DDR installation criteria will require an excessive number of installations, has not been technically justified by the SDT for the increase in DDR installations which will be required, and will be unnecessarily burdensome to the industry. Industry experience shows that disturbance events for which DDR information and analysis is needed are very rare, and we believe the R61.1 criteria puts us closer to what should be a target number of installations rather than a minimum number.
Yes
No
Clearly state the timeframe required for implementation of newly identified locations resulting from the R1 five year assessment.
1) All SER and FR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple requirements. 2) Similar to 1) above, all DDR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple requirements. 3) Add "by voltage level" in Requirement R1 so that it reads "Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR)." This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. 4) In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. Suggest Requirement R5.1 be reworded to say "A single record or multiple records that include at least one of the following:" 5) Reword Requirement R14 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) "If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure." Recommend increasing the allowed repair time by 30 days to allow for non-inventoried repair parts and limited access of repair personnel to such equipment which may be restricted during certain periods of the year.
Individual
Tommy Drea
Dairyland Power Cooperative (DPC)
No
R4. If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The SDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.
No
If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The SDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.
No

Please provide the technical justification for Requirement R6.1.1.
No
It is unclear what the implementation timeframe is for newly identified facilities after the original implementation of the standard. Should a facility be identified in the future as requiring a SOER, FR or DDR it is unclear how long the responsibility entity has to install equipment to capture the necessary data to be compliant.
Group
Duke Energy
Michael Lowman
Duke Energy recommends the following suggestion to the new definitions (1) Dynamic Disturbance Recording (DDR) –The recording of time sequenced data for dynamic power system analysis comprising characteristics such as power flow, and frequency and voltage excursions. (2) Fault Recording (FR) –The recording of time sequenced waveform data, such as current(s) and voltage(s), for short circuits or failure of BES Elements. (3) Sequence of Events Recording (SOER) –The recording of time sequenced data for change in status of BES Elements, which may include components of protection and control systems.
Yes
Yes
Yes
Yes
Yes
(1) Duke Energy believes that ambiguity exists between Requirement 14 and the Rationale. The standard suggests that an entity must “Report the inability to record data to the Registered Entity along with a Corrective Action Plan (CAP) to restore the recording ability” within 90 calendar days. However, in the Rationale for Requirement 14, the language suggests that a Registered Entity must issue a report on the inability to record data to the Registered Entity after a timeframe of 90 days. (2) Triggering of frequency events in Requirement 10 should be adjusted. Significant events will be missed if recorders on generators are set to trigger below 59.75. Also, the rate of change wording is confusing and should trigger if the rate of change is greater than a value not less than a value. Lastly, the Rate of change frequency set point of 125 mHz is too large and should be triggered on generation around 20 mHz per second. (3) Electrical quantities identified in Requirement 9 should better align with MOD-26 (MW, MVARS, Terminal Volts, Field Volts, Field Amps). (4) According to the rationale for R6, the intent of the requirement is to “ensure that there are sufficient BES Elements identified for DDR because of the crucial role DDR plays in wide-area disturbance analysis. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system model’s performance.” Duke Energy believes to require that DDRs be located in areas necessary to monitor all elements of permanent Flowgates is excessive. Permanent Flowgates fall into one of three categories: Voltage, Stability, or Thermal. The majority of the Flowgates identified are classified as being Thermal. Thermal Flowgates are chosen due to concerns with steady-state loading and not for transient/post-transient activity. With some PCs or RCs having as many as 1000 permanent Flowgates, the cost versus reliability gain would be astronomical. For Flowgates that have been identified to be voltage or stability related, the case can certainly be made to have DDRs monitor them in the transient/post-transient timeframe. We suggest that all permanent Flowgates should be removed from the requirement and only keep those permanent Flowgates that have been identified as voltage or stability limited. This would reduce the

amount of Flowgates requiring DDRs, reduce the cost for industry stakeholders, and still achieve the intent of this requirement.
Group
Southern Company
Wayne Johnson
Yes
Yes
Yes
No
a) In the Background section, the SDT explains the basis for the 500MW threshold; however, there is no explanation/ basis for the 300MW at locations over 1000MW. b) It is not clear in R9 whether the specification for signal measurements is on a generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). This determination weighs heavily on the cost and method of implementation where new equipment must be installed. Example: (i.e. combined cycle plant (1075MW total) with units of 325, 325, 425 but only one transmission line)? c) In reference to the R6.1.4: The monitoring of all elements of a permanent flowgate should be changed to only the major elements or perhaps those that contribute more than 20%. In some cases multiple lines of 500, 230, and 115kV may be involved but the lower voltage lines may only contribute 5-10% of the total capacity. Having to install DDR capability at these multiple locations is overly burdensome and does not enhance the overall goal of this Standard.
Yes
No
Referencing Note 9 of the Background section, ‘Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant’; we feel the requirement to be ‘25% compliant within two (2) years following notification of the list’ is problematic and overly burdensome for both TOs and GOs. We feel that a more appropriate timeframe for implementation would be as follows: o At least 25% compliant within three (3) years following notification of the list o At least 50% compliant within four (4) years following notification of the list o 100% compliant within five (5) years following notification of the list
a) The requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation multiple Requirements. b) Similar to a) above, R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation of multiple Requirements. c) The inclusion of the word ‘either’ in R4.1 seems redundant. d) R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record?
Group
El Paso Electric
Pablo Onate

Yes
Yes
Yes
No
No. Requirement 6 contains too many potential DDR locations. SDT should provide clarity between requiring one DDR per system, requirement 6.1.2, versus requirements 6.1.5, 6.1.6 and 6.1.7. The criteria for placement need to be clarified.
Yes
1. In respect to requirement 6.1.4, will entities be required to monitor multiple lines of a major transfer path or only one? 2. In respect to requirement 6.1.5, will one entity owning an HVDC connecting two interconnections be required to monitor both sides of the HVDC element?
Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
PJM does support the methodology and also is providing the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the drafting team should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn't need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
Yes
No
PJM is concerned about the specificty for determination as to the number and location of where DDR will be required per this requirement. Our concerns include the number of DDRs may be sufficient for monitoring but not for data validation. Monitoring lines may not provide the data to adequately perform disturbance analysis. Additionally, the requirment may result in an unnecessary number of installations. We urge the drafting team to provide for the PC to determine the number and location of the devices. Addtionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
Yes

Individual
Joel Charlebois
AESI Acumen Engineered Solutions International Inc.
Yes
Yes
Yes
Yes
Yes
Yes
It is understood that the intent of this version 2 of the PRC-002 Standard is to ensure that sufficient recording capability exists without being prescriptive as to the type of equipment that must be installed to meet the recording capability requirements. It is also understood that the SDT did not wish to be unnecessarily prescriptive with respect to periodic maintenance activities, and as such, this version 2 of PRC-002 contains no such requirement. It does not appear however that the Standard would necessarily ensure that Entities continue to have the required recording capability over time following initial installation and commissioning and after completion of the Implementation Plan. Although an Entity should be compliant at all times, is it plausible that an Entity could be unaware if some of the required recording capability is deficient or no longer exists? Disturbances do not occur very frequently, and an Entity may not become aware of deficiencies for many months or years until a disturbance occurs, when the disturbance data is requested; at which point they realize that the disturbance recording functions or capability is deficient in some manner. It could be argued that verifying compliance, and ensuring that the required recording capability exists, is the task of the auditor; however, this is dependent upon the Standard being included in an audit, and an audit itself may only occur once every 3-6 years. We suggest that the SDT consider adding a requirement for Entities to simply perform a periodic verification of the required recording capability, without specifying how to verify such recording capability, on an interval to be determined by the SDT. There are many mechanisms available for verification such as downloading recorded data, performing equipment self-tests, etc. Allowing Entities to perform periodic verification of the required recording capability in a manner they choose is consistent with the spirit of the Standard of not being unnecessarily prescriptive, and is consistent with ensuring that the required recording capability is in place.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
Believe that applicability to TO and GO entities should be limited to those with the current equipment capable of the required monitoring and should not de facto create a situation where an entity has to purchase equipment to comply with the requirements of the standard, including the storage and auditing of post-fact information sufficent to meet the requirements.

Group
SERC Protection and Controls Subcommittee
David Greene
No
The SERC PCS requests that the SDT to make the following changes: 1. Add ‘balanced, three phase’ between ‘dynamic’ and ‘power’ in order to clarify the context of Dynamic Disturbance Recording. Thus it would read ‘The recording of time sequenced data for dynamic balanced, three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.’ 2. Also the definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3. We do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD.
Yes
Yes
No
1. Our industry experience is that disturbance events for which DDR information and analysis is needed are extremely rare (perhaps one per decade; in fact we’ve not yet experienced such an event). We believe that the proposed R6.1.4 alone would increase our number of NERC required DDR for one of our members at least thirty-fold. The SDT has not provided technical justification for this proposed significant increase. For this member, the other parts of 6.1 may well triple their NERC required DDRs. We ask the SDT to consider a reasonable approach and omit Requirement 6.1.4 and reconsider it in the five-year review of this standard if NERC-wide experience in the meantime warrants it. Perhaps this is a regional issue and some regions have a stronger need; if so, we suggest they draft a regional standard. 2. A quick analysis of another of our members identified 12 generating plant locations (R6.1.3), 18 flowgates (R6.1.4) at 12 locations and one IROL (R6.1.6) location where we own Elements. Presently we are required by SERC to have DDR at 6 locations. This results in the entity possibly needing DDR at 19 additional locations, with a total of 25! Was there any effort, as was suggested in the Atlanta drafting team open forum meeting, for a data request of the REs to assess how many DDRs (Elements) would be need to be monitored? If so where is this information? If this was not done, it must be a part of the cost impact effort. 3. Clarity is needed under Requirement 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. 4. Clarity is needed in Requirement 6.1.4 (if it is retained) when you refer to “monitor all Elements of: all permanent flowgates”. If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. 5. Under Requirement 6.1, it may be better to move the minimum quantities Requirements 6.1.1 (minimum 1 DDR per 3000MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the Requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable Requirements, and state that additional DDR locations are only needed if fulfilling the first 5 Requirements does not meet the two extra minimum quantities Requirements.
Yes

No
1. Extend the GO 100% requirement to 6 years because it better matches the typical major unit overhaul schedule for the large units and plants that this standard targets. 2. Clearly state that the TO / GO has 3 years to attain 100% for any newly identified locations in the five year review.
We request the SDT to make the following changes: 1. The Requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple Requirements. 2. Similar to 1) above, Requirements R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple Requirements. 3. Provide at least one example in the Guidance Section, or develop a reference document similar to the BES Definition effort. A system one line similar to BES Definition Reference Figure S1-1 augmented with circuit breakers in various configurations (e.g. straight bus, ring bus, breaker-and-a-half). The drafting team could go through the various Requirements to demonstrate the SDT intentions. Although the present guidance and rationale are helpful, we believe there are still many unclear aspects to these Requirements. 4. Add ‘by voltage level’ in Requirement R1 so that it reads ‘Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR).’ This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. 5. In Requirements R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. 6. In Requirement R2, it infers that the TO as part of Requirement R1 develop a list of Elements;, however, Requirement R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest Requirement R2 be reworded to say “Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…”. If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. Time has to be allotted to allow identifying the Elements at the BES bus locations. Element ownership sometimes changes between the two terminals of an Element, so this needs to be addressed. GO and TO are each concerned with the unwarranted cost burden this standard proposes, and there will be disputes as to cost responsibility. 7. Use a consistent footer (pages 18 through 40 say Draft 1), and number the pages throughout (they stop at page 25 of 40). 8. Clarify the intent of Requirement R3 which we believe is unclear. The drafting team may intend that a breaker auxiliary contact be connected to the SOER to provide circuit breaker position. Page 32 Guideline for Requirement R3 last sentence implies that breaker status can be determined from the FR. However page 33 last sentence under Recording of Electrical Quantities suggest that these only augment the SOER. 9. Add ‘including generator interconnection facilities’ after Transmission lines in Requirement R4 to be consistent with page 32 Guideline and Project 2010-07. 10. In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. We suggest Requirement R5.1 be reworded to say “A single record or multiple records that include at least one of the following:” 11. Reword Requirement R13 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall provide data for those BES Elements to the Regional Entity upon request.’ The regions already have a process for collecting these types of data and can act as a clearinghouse if indeed the Reliability Coordinator and/or NERC need the exact same data. The reality is that all these entities will collaborate in the disturbance analysis if an event of this magnitude ever does occur. It is unreasonable to require the TO and GO to respond to duplicative data requests in such a short time. 12. Reword Requirement R14 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery

of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure.' Please increase the allowed repair time by 30 days because the access of repair personnel to such equipment is often restricted during certain periods of the year. In addition; revise the second part to be consistent with the handling of Unresolved Maintenance Issues in PRC-005-2 R5. This change triggers an M14 part (3) change to "(3) if not repaired within 120 calendar days of discovery, evidence that it has undertaken efforts to correct the unresolved failure Issues in accordance with Requirement R14. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.' We believe that the proposed reporting requirement is much too burdensome for this equipment.
Individual
Angela P Gaines
Portland General Electric Company
No
Portland General Electric Company (PGE) appreciates the standard drafting team's efforts in crafting this proposed standard and understands the importance of the data that will eventually be available once the standard is implemented. However, a four (4) year implementation window may not be enough time if an entity is required by its Responsible Entity (in our case, the RC) to install several disturbance monitoring units. It is interesting to note that an entity that has only one element to implement has the entire 4 year window to do so. However, if an entity has 2 elements, for example, that entity does not get 8 years to implement but, in effect, has half the time. The more elements required to be implemented, the less overall time an entity has to do so. PGE suggests letting the RC develop an implementation timeframe based on the elements it determines an entity needs to install. Depending on the number of elements required, an entity would be considered compliant as long as it was meeting specified and agreed upon milestones. The triggering of the negotiated timeframes could be based on a pre-determined number of elements, i.e. >4, or on a business-justified request from the entity for an extended implementation window. To suggest that an entity is non-compliant because all necessary projects are not fully completed after a 4 year implementation window fails to distinguish between entities that have taken no action whatsoever and entities that have projects and activities in progress well ahead of the effective date of this proposed standard.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
No
Requirement R1, Attachment 1 - ReliabilityFirst questions the rational to not require any Fault Recording and Sequence of Events Recording if there are no buses that fall on the list (i.e. an entity has no buses with maximum available calculated three phase short circuit MVA of 1500 MVA or greater). ReliabilityFirst believes to effectively recreate events using Fault Recording and Sequence of Events Recording data, Transmission Owners that have no buses on the list should still be required, at a minimum, to have at least one BES bus location with Fault Recording and Sequence of Events Recording. It could be required at least one BES bus location with the highest maximum available calculated three phase short circuit MVA. In order to achieve this, ReliabilityFirst

recommends the first sentence in Step 7 ("If there are no bus locations on the list: the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9."), be removed from the methodology. Also, even though ReliabilityFirst believes the template for determining Fault recorder and SOE bus locations is helpful, ReliabilityFirst recommends developing a step by step example detailing the locational selection methodology.
No
Applicability - ReliabilityFirst understands the rationale behind differentiating the Responsible Entity per Interconnection, but does not agree with ERCOT still stating "Planning Coordinator or Reliability Coordinator". ERCOT is both the Planning Coordinator and Reliability Coordinator so the SDT needs to decide which function in ERCOT will be responsible for determining DDRs to avoid any future confusion for monitoring compliance.
No
Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 ("Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA), does this mean only individual units which are greater than 300 MVA and part of plant need to have DDRs? If this is the case, it appears that a plant that has five 200 MVA units does not require DDRs. Is this the SDTs intent? ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR.
No
VSL for Requirement R3 (the same rationale in this comment also apply to the VSLs for Requirement R4,R5, R8, R9, R10 and R11) - ReliabilityFirst believes the gradation of VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). For example, if an entity only implemented 59% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers, this does not meet the intent of the requirement and therefore should be a "Severe" VSL.
Requirement R4, Part 4.2.1 - With the forthcoming approval of the NERC BES Definition including "Transformers with the primary terminal and at least one secondary terminal operated at 100 kV…", ReliabilityFirst does not believe the informative language in Requirement R4, Part 4.2.1 is needed and recommends removing the following language from Requirement R4, Part 4.2.1: "that have a low-side operating voltage of 100kV or above" since it serves no purpose. Requirement R14 - ReliabilityFirst does not believe there is any value for an Entity to report their inability to record data (due to a failure of a FR, SOER or DDR) to the Regional Entity. ReliabilityFirst believes the record keeping will be burdensome with little or no benefit. ReliabilityFirst would rather like to see the Entities get the corrective actions plans in place and the equipment fixed, thus the Regions really have no need for this type of report. Compliance can be monitored through a data submittal on an annual basis rather than an ongoing reporting requirement. Also, even though a bulleted list in a Reliability Standard indicates an "or" statement, it is still unclear that these are considered two options. ReliabilityFirst recommends adding the word "either" after the word "shall" in the parent Requirement R14 and including the word "or" after the word "ability" in the first bullet. ReliabilityFirst also recommends the following to remove the Regional Entity from the second bullet and adding a timeframe for when the CAP needs to be completed (it should not be open ended): "Develop and implement a Corrective Action Plan (CAP) to restore the recording ability within xx days." Also, the CAP should not have an open-ended timeframe for completion, such as years into the future. There needs to be some time limit for correction.
Group
SPP Standards Review Group
Robert Rhodes
No
To maintain parallel structure in the definition of Dynamic Disturbance Recording (DDR) we suggest changing 'abnormal voltage problems' to 'abnormal voltage deviations'. The acronym for Fault Recording (FR) may be confused with that of Frequency Response as has been previously defined in BAL-003. Would it be prudent to change one or the other? Insert 'which' in the next to last line of

the Rationale Box such that it reads '...proliferation of multiple function devices, and the intent of the Standard which is to address the result, not the how...'
Yes
Insert an 'a' in the 6th line of the 2nd paragraph of the Rationale Box such that it reads '...have a significant effect on system reliability and performance. Conversely, locations with a very low short...' We suggest the drafting team watch for consistency in the use of the adjective 'three-phase' throughout all the posted documents. Make sure it is properly hyphenated.
Yes
We thank the drafting team for deleting the Reliability Coordinator as an Applicable Entity in the Eastern Interconnection.
No
Requirement R6.1.3.2 requires DDR for all generating units greater than 300 MVA at a plant/facility with an aggregate nameplate rating equal to or greater than 1000 MVA. Does this apply in situations where the generating units may be connected at different voltage levels within the plant/facility? Especially those which may not even be tied together within the plant/facility? Requirement R6.1.4 requires DDR for all permanent Flowgates within the Eastern Interconnection. We believe this requirement is troublesome for several reasons. First, Flowgates can be added on the fly in Real-time. Although these Flowgates are at that time temporary, they can become permanent at the end of the month in which they were created in the Book of Flowgates. Thus a Transmission Owner would then be responsible for having DDR equipment on that Flowgate within less than 30 days. This is an unreasonable request. Additionally, most Flowgates are thermally limited and not all of them represent facilities which have a significant impact on the BES. They may have been created to address localized loading issues. As such, requiring these facilities to be monitored by DDR equipment is excessive and does not contribute significantly to the reliability of the BES. On the other hand, there may be other Flowgates which do consist of or represent facilities which can have a tremendous impact on the BES. Some of these Flowgates are there specifically to address voltage stability and dynamic system stability issues. These facilities need to be monitored by DDR equipment. The difficulty becomes determining which Flowgates fit the latter category. The drafting team needs to put some effort into determining the criteria to use in deciding which Flowgates are worthy of DDR monitoring.
Yes
We note in several of the Severe VSLs that quantifiers of greater than 0% but less than 10% are used. However, in Requirement R11, the quantifiers are greater than 1% but less than 10%. Was the 1% intended or should it have also been 0%?
Requirement R2 calls for Transmission Owners to notify other owners (who would also be Transmission Owners) of other facilities within the locations identified in Requirement R1. There could conceivably be situations where multiple owners would be involved and possibly none of the owners was able to identify 11 locations as specified in R1. In this situation, those particular facilities would not be required to have SOER or FR equipment even though the impact of those facilities could be significant on the BES. While this situation may be very unlikely to occur, it is still a possibility. In Requirement R2 and its associated Rationale Box as well as throughout the posted documents, check for hyphenation of terms such as 90-calendar days, 60-calendar days, 30-calendars days, etc. In the Rationale Box for R8 modify the single-line, paragraph to read 'Because all of the buses within a location are typically at the same frequency, one frequency measurement is adequate.' In the 1st paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis, modify the next to last line to read '...voltage and current for individual circuits allow precise reconstruction of events of both...'. Check the usage of wide-area and make sure it is properly hyphenated throughout the standard and the posted documents. Something appears to be missing in the 2nd sentence in the last paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis. 'Five years is long enough to avoid unnecessary, but long enough to adapt...'. To avoid unnecessary what? In the 1st line of the 2nd paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis, change 'Pre and post...' to 'Pre- and post-...'. In the 2nd line of the same paragraph, change 'SOE' to 'SOER'. In the 6th and 8th lines of the same paragraph, hyphenate '50-cycle post trigger'. In the 2nd line of the 4th paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis,

replace ‘Oscilloscope’ with ‘oscilloscope’. In the 7th line of the 4th paragraph under Guideline for Requirement R6 section in the Guidelines and Technical Basis, modify the line to read ‘...interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the...’. In the Guidelines for Requirement 7 and Requirement 12 in the Guidelines and Technical Basis, the reader is referred to the Rationale Boxes in the standard for the information on those requirements. Once the standard is approved, the Rationale Boxes will disappear. We suggest going ahead and inserting the material from those boxes here even if it is redundant. In the 1st line of the 1st paragraph under Guidelines for Requirement R8, revise the line to read ‘Dynamic Disturbance Recording measures transient response to system disturbances after a fault is...’. In the 3rd line of the 1st paragraph under Guidelines for Requirement R10, revise the line to read ‘...analysis. Pre- and post-contingency data help identify the causes and effects of each event...’. Modify the 1st line of the 1st paragraph under Guidelines for Requirement R11 to read ‘Dynamic Disturbance Recording contains the dynamic response of a power system to a...’ or ‘Dynamic Disturbance Recording contains the dynamic response of power systems to a...’. In the 3rd line of the same paragraph hyphenate ‘short-term’ and ‘long-term’. In the 4th line of the same paragraph delete the ‘the’ such that the line reads ‘...interest is changing over time, Dynamic Disturbance Recording is normally stored in the...’. We suggest the following to replace the 1st sentence in the 1st paragraph in the Guideline for Requirement R13: ‘This requirement directs the applicable entities, that upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SOER and FR data for locations determined in Requirement R1 and DDR data for Elements determined in Requirement R6. Replace ‘was’ with ‘were’ in the 4th line of the 6th paragraph in the Guideline for Requirement R13 section of the Guidelines and Technical Basis. We suggest the drafting team number the pages in Attachment 1 and the Guidelines and Technical Basis document.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
AECI Supports comments posted by SERC PCS In addition, AECI particularly questions the value and technical rationale for citing all permanent flowgates. There are several types of permanent flowgates, and not all would correlate to the BES Reliability purpose to warrant DDR measurements at either end. Is it this SDT's intent to move the Eastern Interconnection away from flowgate methodogy for assessing impact and capacity for commerce across its bulk transmission system? If the other specified technical assessments have merit, then busses terminating any flowgates significant for DDR will show up.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
City of Austin dba Austin Energy (AE) believes that the proposed PRC-002-2 standard is overly prescriptive and provides unnecessary requirements that are already addressed by Regional rules, guidelines, requirements, etc. For example, ERCOT has requirements for installing Disturbance Monitoring Equipment (DME) that may address more specific regional needs, considering ERCOT system characteristics. Additionally, AE believes the standard, as proposed, would be costly to implement.
Group
Bureau of Reclamation
Erika Doot

Yes
Yes
Yes
Yes
Yes
Yes
Individual
Karin Schweitzer
Lower Colorado River Authority
Yes
Yes
Yes
No
Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the “Lower” range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Yes
Yes
R3 – clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. R3, R4, R5, R11, R12, R13, R14 – Clarify “AND” in requirement and “OR” in measure – language is confusing. It is inconsistent. R5 – Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. Change 5.3 to “Trigger settings for at least one of the following:” –OR– remove Phase undervoltage as a trigger requirement. R13 – revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. R14 – change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
Group
Santee Cooper
S. Tom Abrams
No
We agree with the SERC PCS comments.

Individual
Martyn Turner
LCRA Transmission Services Corporation
Yes
Yes
Yes
No
Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the “Lower” range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Yes
Yes
R3 – clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. R3, R4, R5, R11, R12, R13, R14 – Clarify “AND” in requirement and “OR” in measure – language is confusing. It is inconsistent. R5 – Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. Change 5.3 to “Trigger settings for at least one of the following:” –OR– remove Phase undervoltage as a trigger requirement. R13 – revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. R14 – change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
Individual
John Brockhan
CenterPoint Energy Houston Electric
Yes
Yes
Yes
No
CenterPoint Energy understands the potential usefulness of dynamic data for event analysis and supports the collection of dynamic data for event analysis as a Best Practice. However, the Company’s experience has been that sufficient data for event analysis is available from existing fault recording devices and therefore is strongly opposed to inclusion of a requirement to provide dynamic data. The only way to provide dynamic data is through a dynamic recording device. If an entity does not currently have any dynamic recording devices installed on its system then the entity has little choice but to spend capital in order to acquire and install these devices to comply with the Requirement. CenterPoint Energy does not believe the enabling legislation allows for Reliability Standards to require the expenditure of capital funds. While the SDT contends the requirement is only for dynamic data, not the installation of dynamic recording devices, and an entity is free to determine how it will comply, CenterPoint Energy finds this argument disingenuous. CenterPoint

Energy strongly recommends the deletion of this requirement. The Company cannot support any draft Standard that contains such a requirement.
No
CenterPoint Energy is concerned the proposed Implementation Plan does not allow sufficient time for entities to make arrangements with other entities or, if needed, to install required devices or communication devices. Based on Requirement R6 the ERCOT Region would require approximately 18 – 20 DDR's and several times that amount of SOER's. The installation of DDR's and SOER's would require scheduling outages on possibly hundreds of pieces of equipment. The scheduling and coordination of this amount of planned outages is simply not possible within the allotted timeframe. CenterPoint Energy recommends expanding the Implementation Plan to three to five years.
1. CenterPoint Energy believes the intent of some of the requirements is unclear without the corresponding Rationale box. It is our understanding that auditors may consult the rationale and other information to be placed in the Application Guidelines section; however, auditors must always refer to the requirement language. Therefore, the language of the requirements should clearly explain the intent of the requirement with less reliance on the Rationale boxes. For example; Requirement R13.2 should identify the data retrieved as only the data measured within 10 days preceding a request. Recommend modifying Requirement 13.2 to read "Only recorded data measured and recorded within 10 days prior to a request will be retrievable." The Rationale box for R13 clarifies the intent of the requirement; however the language should be more specific. The language for requirement R14 should explicitly identify the sub-bullets as an "or". Furthermore, CenterPoint Energy recommends modifying the second bullet of Requirement R14 to read "If the recording ability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability."
Individual
Steve Hill
Northern California Power Agency
Yes
No
Seems excessively tedious for all TOs. Transmission Owners need to produce Transmission Studies per TPL standards. Steps 1 & 2 can be obtained from those studies. Steps 3&4 and second paragraph of step 7 seem arbitrary. Why 11? Please justify the second paragraph of step 7.
No
WECC has a Synchrophasor program. Why would not the RE or the appropriate RC identify the areas where this equipment is located and continue with the existing program?
Yes
Generally yes; however this should be consistent with WECC's continued synchrophasor program
No
No because I do not support the registraton process
No
I do not agree with the registration
I support the comments of FMPA from Frank Gaffney
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PCS
Individual
Christina Conway
Oncor Electric Delivery

Yes
Yes
Yes
No
The R6.1 sub-requirement describes minimum locations. There are no limitations on the DDR requirements written into the standard language. This could potentially lead to the Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) overburdening the TO/GO with the volume of included locations. The language in R1 provides a “20%” audit curtailment for the FR/SOER but there is no similar language for the DDRs in R6.
Yes
Yes
General: Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. It is understood the Rationale Boxes will be retained but relocated to the Application Guidelines Section of the Standard. However, incorporating the Rationale/intent language into the Requirement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore Oncor recommends the Standard Drafting Team review the Requirement language and the corresponding relocated Rationale language to ensure there are no gaps once moved to final state. Additional details provided below. R1: To clarify the line/bus distinction, Attachment "BES Sketches - Facility Example & Boundary Definitions" should be added to the Standard. R2 and R6.2: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists, but the Requirement language itself does not include post-implementation compliance timelines for the required reassessments. The Implementation Plan states "Entities shall be 100% compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three (3) years following notification of the list." This language should also be included in the language of the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3: Legacy FR equipment installed before the standard effective date may not be capable of embedded SOER. R3 does not afford the same caveat for older equipment where SOER is required that R10 provides for older equipment where DDR is required. Language should be added to R3 providing the option to utilize FR digitals to monitor circuit breaker position for each circuit breaker. R4 and R8: Add Rationale box stipulation that the required “electrical quantities, whether directly measured or derived,” to R4 and R8 as described below: The R4 Rationale Box explains the method of deriving electrical quantities; however, the requirement language of R4.1 does not reflect the intent described in the Rationale Box. Specifically, whether or not locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each phase-to-neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for “each line or bus.” The language of R8.3 does not specify the method used to provide “Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.” If the intent follows the electrical quantity collection of R4, the language of R8 should also specify the ability to derive electrical quantities. Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR. R10: The language of R10 could be interpreted to mean the triggering requirements are only applicable to DDR equipment installed prior to the effective date of the standard. The triggering requirements are applicable to all DDR equipment. Additionally, the collection of 3-minute FR records for every transient event as a substitute for a DDR is a costly modem transfer and storage retention practice. R11: If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR analysis. R12: The language of R12 should provide a caveat to allow for manipulating event records to UTC

for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the “or derived” language suggestions to Requirements R4 and R8 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M12 evidence. Additionally, Rationale box language, further explaining the UTC local offset, should be included in M12 to clarify that offset records are acceptable as evidence. In other words, requested records must be supplied in UTC format, but the stored format does not need to adhere to UTC format. R13: Some entities do not automatically name files in the COMNAME format for ease of data storage. With the phrase “formatted records,” M13 implies that manipulation of file before submittal is allowed. If data file names can be changed to the prescribed COMNAME formatting, R13.5 should specify that the data files need only be provided in this format rather than originally named this way.
Individual
Michael Moltane
ITC
Yes
Yes
Yes
No
6.1.4 for Eastern Interconnection “permanent Flowgates” rather than using a blanket approach to require DDR on all defined Flowgates, they should be selectively placed on those Flowgates that have a chronic congestion history. The DDRs should be placed on the defined monitored element(s) of permanent flowgates that exhibit a history of chronic congestion
Yes
Yes
R4, R11, R12, R13 and R14 need to be clear that they apply to the Element and/or equipment owner. They will be acceptable if they are reworded as: R4 after “following electrical quantities” insert “for each of the Elements they own” R11 after “for the Elements” insert “they own” R12 and R13 after “Dynamic Disturbance Recording (DDR) data for” insert “for Disturbance Monitoring Equipment they own” R14 after “or Dynamic Disturbance Recording (DDR)” insert “that they own”
Group
Bonneville Power Administration
Andrea Jessup
No
BPA feels the definitions are not succinct enough to explain to someone exactly what it is they’re being required to do.
Yes
No
BPA feels that responsible functional entities — as well as roles and responsibilities — must be clearly identified in the Standards and requirements. As the Standard is currently written, BPA feels that too much credence is given to assumptions outlined in the Standard and, unless clearly defined, these assumptions will not pan out as described.
No

a) BPA feels there should not be a requirement to monitor all elements of a path/interface/IROL when three of five lines can supply enough understanding (used in conjunction with other DME); and b) The IROL should be determined by Planning Criteria, not by a dynamic/ever-changing IROL.
No
BPA feels that R6 should remove “x percent” of the identified Elements (or Busses) and keep the time-based VSL.
Yes
A. Introduction 4. Applicability 4.1 The Responsible Entity is: BPA feels that under this section planning coordinators and reliability coordinators are named as the responsible entities which are later tasked with determining the necessary locations for dynamic disturbance recording equipment. This was one of the primary issues with the previous version of the standard, PRC-018. These entities failed to write such standards and therefore the standard lacked the necessary content for transmission and generation owners to apply. This basis will face similar challenges. Additionally this delineation of the responsible Entity takes authority away from the TOs and GOs to operate their monitoring systems in a way that makes good financial and operational sense for their individual companies. This definition should also be expanded to include Transmission Operators and Generation Operators. B. Requirements and Measures R1. BPA feels the substance of this section is based on the Attachment 1, which is later labeled as Attachment A, so it is on that section that comments shall be provided. The methodology presented in Attachment 1 is overly complex and does not present a sound technical basis for the location of DFRs and SERs. Monitoring locations above 1500MVA are subject to selection based on mathematical manipulation for which no system impact basis is provided. A final step of “engineering judgment” is then applied in order to round out the list. This methodology may not result in consistent or repeatable bus selection for the placement of DFRs and SERs and will be difficult to defend in an audit scenario. This use of an MVA based location criteria is not consistent with other system impact based criteria currently being used within the NERC standards, such as CIP-002-4 & 5, nor with draft versions of the WECC disturbance monitoring standard. R2. BPA feels this requirement places a compliance burden on the Transmission and Generation owners for equipment over which they have no control. TOs and GOs might be responsible for bus identification and notification of other entities with interconnections to those busses but the identification of individual BES elements and the associated compliance burdens should be left to those with operational responsibility for those elements. R3. BPA feels this requirement refers to R2 in the text I believe this reference should be to R1 as R2 does not define bus locations. R4. BPA feels that this requirement needs to be clarified. Specifically, BPA feels that not all line voltages are required if there is no bus (with two lines minimum). R5. BPA feels that in sections 5.1 and 5.2 specific record lengths and sample rates are delineated. The standard goes too far in mandating equipment specification for the Transmissions and Generation owners. The development of equipment specification must be left to the individual owners and operators in order for them to effectively balance cost and operational requirements. R6. BPA feels the responsibility for the sighting of DDRs should be assigned to the Transmission/Generator Operator/Owner not the reliability coordinator. The Operator/Owner must be left to identify BES elements which require dynamic disturbance recording equipment. This may be easily and consistently accomplished through the application of bright line criteria. The criteria provided in 6.1 are insufficient. The criteria do not account for operating voltage or equipment such as series capacitor installations which could contribute to sub synchronous resonant situations. A comprehensive set of bright line criteria for DFRs, SERs, and DDRs must be developed. These criteria should be consistent with similar criteria used in other NERC and industry standards. Any list of locations which is delineated by a Responsible entity must be subject to some adjustment by the affected TO or GO. R7. BPA feels the Transmission/Generation Owner/Operator must be responsible for the identification of locations which require DDRs not the Reliability Coordinator. Only in this manner may the individual TOs and GOs achieve visibility of their own systems. R14. BPA feels the requirement needs to clearly indicate that it is an “OR” distinction between the two bullets. So that one-hour or one-day equipment reporting and corrective action plan is not required at the time of discovery, but rather (as is intended) only after 90 days of failure.
Group
Colorado Springs Utilities

Kaleb Brimhall
No
No
No
No
Yes
As shown in the VRF levels (all "lower"), we do not believe that there is sufficient reliability justification to make this a standard.
No
Thank you standard drafting team for all of your efforts. We believe that all of the disturbance monitoring equipment referenced in this standard can be very helpful to an organization. We do not believe that it has a reliability impact that merits the cost in time and money to install, maintain, and report on all these devices as specified in the standard. As shown by the VRFs this does not highly impact reliability and although disturbance monitoring is something that could be useful, at times, should not be part of a mandatory standard. If a standard is to be implemented, we view the approach as written, to be too broad and cumbersome. We would recommend that a technical criteria based on system configuration be established to identify critical points for disturbance monitoring (DM) and that DM be implemented at those locations. We believe a more focused and technically based approach to placement of DM equipment would yield higher benefits while eliminating unnecessary and undesirable impacts.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
We believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Yes
We agree, however some clarity should be added: 1) In R6, mention is made of both Elements and locations for locating DDR. Is the intent to have the location be an entire substation, an entire bus, or a single Element? Or is that entirely at the discretion of the Responsible Entity? 2) R6 refers to generating resources with individual nameplate capacities. For a combined cycle plant, does the individual nameplate capacity of the resource refer to the combined unit or the individual turbines? Recommend making this more clear. 3) Is the list in R6 intended to be an all-inclusive list or is it a minimum list? If it is a minimum list, there is a concern that the standard may allow one entity to put increased costs on another entity, for example a Reliability Coordinator that wants a DDR on every generator, regardless of size. We ask the drafting team work to address this issue. We recommend that the drafting team determine the list of places that need a DDR and redraft the requirement to eliminate the responsible entities of the RC and PC and instead just require the owner of elements that meet the specifications install DDRs.
No

1) Our concern with the implementation plan is that its milestone requirements are significantly different from requirements for similar equipment in PRC standards that are now awaiting final FERC approval. Specifically, PRC-019, PRC-024, & PRC-025 involve the same facilities and all have 5 year implementation plans (with some caveats). Yet the implementation plan for PRC-002 is 4 years. When entities are considering work planning and execution, it would be more efficient to provide an implementation schedule that allows 'campaigns' at generation facilities to address all of the protective system equipment changes due to the suite of PRC standards under one maintenance project. (This is especially critical when considering this work will likely require an outage.) Therefore, Xcel Energy recommends PRC-002 utilize the same phased in schedule as PRC-019, PRC 024 and PRC-025. At a high level, the modification would be to change the implementation plan to: [Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13: -Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is not necessary, the first day 60 months from notice of applicability of R1 or R6. -Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is necessary, the first day 84 months.] 2) Finally, the standard is written such that the requirements are phased in over time. However, there is no period identified for the TO or GO to become compliant after any change in the points identified. As an example, in 2020, if the TO determines in R1 that a new point needs a device, R2 allows them 90 days to notify the owner of that equipment. Yet, for R3, R6 and R7 there is no established period of time for the TO or GO to make such an installation. We recommend the drafting team add in an implementation period for newly identified points beyond the immediate phased-in implementation of the standard.
1) It appears that a lot of individual requirements are written for something that isn’t overly complex. Please consider consolidating R8-R11, or consolidating the technical specs that comprise R5, R11, and R12. 2) In R14, its not clear why the Regional Entity is introduced here. Also, the Regional Entity would take on the burden of tracking corrective action plans, if the recorder isn't restored in the 90 day period. Recommend changing Regional Entity to Reliability Coordinator.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
Yes
Would like more information as to how the 1500 MVA value was decided upon.
Yes
No
DDR installations have been resource intensive and problematic to install and to place on-line. Section 6 opens the door for quite a number of DDR deployments. Section 6.1.4 requires the monitoring of all Elements of major transfer paths on the Western Interconnection. Utilities in the Western Interconnection have already participated in WECC’s WISP program and have installed and commissioned DDR’s as required. DDR deployment per WISP should be considered sufficient in the WECC footprint.
Yes
Yes
Overall, the implementation program appears reasonable. However, the work involved is linked to the requirements of the standard which could possibly change. The requirements of R6 may be difficult to meet as written. See comments under Question 4.
Section 5.3 – Disagree with the trigger requirements as written. There are many factors that contribute to effective triggering such as: • Triggering for local vs. remote faults • Avoiding over-triggering that could result in “information overload” and the filling up of data storage • Capturing relevant and complete fault representation The requirements stated are inadequate. It is felt that trigger settings are best left to the professional judgement of the relay engineer. While triggering on

Neutral (residual) overcurrent is often standard, care must be taken regarding the sensitivity level. Similarly, triggering issues related to sensitivity and pickup time are associated with phase undervoltage triggering. Other triggering methods (such as based on protection element pickup) may be preferred instead of undervoltage methods. Section R13 – the requirements of R13.4 and R13.5, while achievable, are somewhat archaic. More flexibility should be allowed for frequently used, industry standardized fault recording formats such as SEL event records. Also, the naming convention put forth in C37.232 is not the easiest to follow.
Individual
Russell Noble
Cowlitz PUD
Agree
FMPA's comment submitted by Frank Gaffney