

Unofficial Comment Form for Relay Loadability Order (No. 733) (Project 2010-13)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit **FORMAL** comments on the proposed second version of the Relay Loadability Standard PRC-023-2 that includes the applicability test in Attachment B. The electronic comment form must be completed **by December 16, 2010**.

If you have questions please contact Joe Bucciero at joe.bucciero@gmail.com or by telephone at 267-981-5445.

Background Information

NERC Standard PRC-023-1 – Transmission Relay Loadability was approved by FERC as mandatory and enforceable in March 2010, with direction that NERC make a number of changes.

The Standard Drafting Team made changes to PRC-023-1 to address the following directives from Order 733

- p. 60 . . . modify PRC-023-1 to apply an “add in” approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- p. 224 . . . make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-requirement R1.12.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the “Effective Dates” section.

The Standard Drafting Team posted the proposed changes for informal industry comment from August 19, 2010 to September 19, 2010. The proposed changes did NOT include Attachment B to the standard as it was still a work in progress at that time. Attachment B contains the applicability test that the Planning Coordinators must use to determine whether a sub-200kV facility must comply with PRC-023. The inclusion of a test is a directive in Order No. 733:

- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.

Requirement R6 of the draft PRC-023-2 standard (formerly Requirement R3 of PRC-023-1) states:

R6. Each Planning Coordinator shall apply the criteria in Attachment B to an assessment conducted at least once each calendar year, with no more than 15 months between assessments, to determine which transmission Elements must comply with this standard. The Planning Coordinator shall:

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

- 6.1 Apply the criteria to transmission lines that are operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- 6.2 Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area.
- 6.3 Maintain a list of facilities determined according to the process described in Requirement R6.
- 6.4 Include on the list the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable.
- 6.5 Provide a list of facilities to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator Area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

In response to comments during the informal posting the SDT has replaced the phrase “critical to reliability of the bulk electric system” with “must comply with this standard.” The SDT notes that although the phrase “critical to reliability of the bulk electric system” appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion.

Use of the phrase “critical to reliability of the Bulk Electric System” in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. Reliability is adequately addressed in Attachment B since it identifies all of the facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

A Blue Ribbon Panel was formed by NERC to develop that required Attachment B to PRC-023-2, which was separately posted for informal industry comment from September 23, 2010 to October 12, 2010.

Applicability Testing Criteria

NERC Reliability Standard PRC-023 — Transmission Relay Loadability was developed in answer to relay loadability problems highlighted during the blackout of 2003. Relay loadability has been either causal or contributory to a majority of major system disturbances dating back to the 1965 blackout and beyond. The proposed Standard is intended to prevent circuits from prematurely tripping due to relay loadability when thermally overloaded. The concept is to allow some time for system operators to intervene and alleviate the overloads.

If any circuit trips under adverse conditions, even if the loss of that circuit does not itself cause a cascade, the resultant weakened transmission system leaves the bulk electric system more exposed to possible cascading outages. Therefore, applicability of PRC-023 should not only be for operationally significant circuits that could cause a cascade, but also for circuits that are prone to overloads (relievable through operator action) during contingencies.

Planning coordinators test for conformance with the TPL standards through various contingency analyses that should prevent critical circuits from becoming overloaded. The TPL criteria contingencies studied normally screen for susceptibility to cascading and system instability. However, overloading of circuits for short periods of time is permissible, and assumes operator action can alleviate such overloads in a timely fashion. Although the planning tests are fairly rigorous, they are usually limited to N-1 or N-2 level contingencies. However, it is for the unforeseen combinations of outages that assurance is necessary that circuits would not trip for relay loadability reasons.

The recommendations stemming from the 2003 blackout called for review of circuits 200 kV and above. Logically, all circuits, including those below 200 kV, that are operationally significant to the reliability of the bulk electric system (BES) should be tested for susceptibility.

System studies go to great lengths to determine transfer capabilities on critical transmission interfaces. Planning and operational studies are routinely conducted to determine the transfer capabilities of circuits such as those that are part of interconnection reliability operating limits (IROLs), flowgates in the Eastern Interconnection, major transfer paths in the Western Interconnection, or comparable monitored elements in the Texas Interconnection or Québec Interconnection. Any circuit that is important enough to reliability to be actively managed to prevent overloads should also be important enough to prevent it from inadvertently tripping due to relay loadability for combinations of outages that are not normally tested.

Note: The criteria included in Attachment B define the family of circuits operated below 200 kV that must comply with PRC-023. If the protection systems on these circuits comply with the Requirements of PRC-023, no further action is necessary. Any protection systems that do not comply would require mitigation.

Implementation Timeframes

Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption except as noted below.

- For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.
- For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Questions

The SDT has considered all of the industry comments submitted during the informal comment period, and has revised and updated the PRC-023-2 standard to incorporate the comments received in this posting of the complete standard. Your responses to the following questions will assist the SDT for Project 2010-13 Relay Loadability Order 733 in finalizing the work for PRC-023-2 relative to the proposed modifications summarized above.

For each question, please indicate whether or not you agree with the requirement being proposed. If you disagree with the changes to the proposed requirement, please explain why you disagree and provide as much detail as possible regarding your disagreement including any suggestions for altering the proposed requirement that would eliminate or minimize your disagreement. The SDT would appreciate responses to as many of these questions as you are willing to supply.

1. Requirement R1 defines the criteria for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Criterion 10 of Requirement R1 was modified to ensure that protection settings do not expose transformers to fault level and duration that exceeds their mechanical withstand capability. Do you agree with the

modification to criterion 10 in Requirement R1? If not, please explain and provide specific suggestions for improvement.

Yes

No

Comments:

2. Requirement R2 requires the evaluation of out-of-step blocking schemes to verify that the out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. Note this new Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1. Do you agree with the requirement included in Requirement R2? If not, please explain and provide specific suggestions for improvement.

Yes

No

Comments:

3. Requirement R4 requires the Registered Entities that choose to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide the Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. Do you agree with the requirement included in Requirement R4? If not, please explain and provide specific suggestions for improvement.

Yes

No

Comments: We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances.

Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.

4. Requirement R5 requires the Registered Entities that set transmission line relays according to Requirement R1 criterion 12 to provide a list of the facilities associated with

those relays to the Regional Entity at least once each calendar year, with no more than 15 months between reports. Do you agree with the requirement included in Requirement R5? If not, please explain and provide specific suggestions for improvement.

- Yes
 No

Comments: While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.

5. Requirement R6 requires each Planning Coordinator to apply the criteria in Attachment B to determine which transmission Elements must comply with this standard. Do you agree with the requirement included in Requirement R6? If not, please explain and provide specific suggestions for improvement.

- Yes
 No

Comments: It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest.

Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.

Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.

6. "Requirement R7 requires the Registered Entities to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that the Planning Coordinator added to the list of facilities that must comply with this standard (per Requirement R6) by certain dates following notification by the Planning Coordinator. Do you agree with the requirement included in Requirement R7? If not, please explain and provide specific suggestions for improvement.

- Yes
 No

Comments: We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to

comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.

7. Attachment A, section 1.6 has been revised to avoid unintended negative impact on reliability associated with referring to “Protective functions that supervise operation of other protective functions.” Section 1.6 has been revised to “Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications” to be more specific to the concern stated in Order No. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain and provide specific suggestions for improvement.

Yes

No

Comments:

8. Attachment B contains the test that the Planning Coordinators must use to determine which transmission elements (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) must comply with this standard. Do you agree that the method proposed in Attachment B is a technically sound approach? If not, please explain and provide specific suggestions for improvement.

Yes

No

Comments: While we appreciate the drafting team’s effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC’s definition of flowgate includes two components. Let’s focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team’s attempt to resolve this issue by including the caveat “that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.” However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded.

Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used.

We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category

B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive.

In response to comments that did not support this criterion during the first posting, the standards drafting team responded with “Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met.” We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.