NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

July 30, 2008

**VIA ELECTRONIC FILING**

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

**Re:** ***North American Electric Reliability Corporation,***
**Docket Nos. RM08-__-000 and RR08-__-000**

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this filing in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Commission's regulations, seeking approval for one reliability standard: PRC-023-1 — Transmission Relay Loadability that is contained in **Exhibit A** to this petition. This proposed reliability standard is submitted for the first time for Commission approval and addresses in part key recommendations from the final report on the 2003 blackout.

This proposed standard was approved by the NERC Board of Trustees on February 12, 2008. NERC requests that PRC-023-1 be made effective consistent with the implementation plan accompanying the reliability standard.

NERC's petition consists the following:

- This transmittal letter;
- A table of contents for the entire petition;

- A narrative description explaining how the proposed reliability standards meet the Commission’s requirements;
- Reliability Standard PRC-023-1 submitted for approval (**Exhibit A**);
- Standard Drafting Team Roster (**Exhibit B**);
- The complete development record of the proposed Reliability Standards (**Exhibit C**); and
- “PRC-023 Reference – Determination and Application of Practical Relaying Loadability Ratings” (**Exhibit D**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

*/s/ Rebecca J. Michael*
Rebecca J. Michael

*Attorney for North American Electric Reliability Corporation*

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION** | **) Docket Nos. RM08-__-000**<br>**) RR08-__-000** |

**PETITION OF THE**
**NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION**
**FOR APPROVAL OF PRC-023-1 RELIABILITY STANDARD**


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July 30, 2008

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## I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission (the "Commission" or "FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5, one reliability standard, PRC-023-1 — Transmission Relay Loadability Reliability Standard. This petition is the first request by NERC for Commission approval of this proposed Reliability Standard.

On February 12, 2008, the NERC Board of Trustees approved PRC-023-1 reliability standard proposed by NERC. NERC requests that the Commission approve the reliability standard and make it effective in accordance with the implementation plan included with the reliability standard and in accordance with the Commission's procedures. **Exhibit A** to this filing sets forth the proposed reliability standard. **Exhibit B** contains the Standard Drafting Team roster. **Exhibit C** contains the complete development record of the reliability standard. **Exhibit D** contains a reference document, "PRC-023 Reference – Determination and Application of Practical Relaying Loadability Ratings," prepared to support the implementation of the proposed reliability standard.

NERC also is filing this reliability standard with applicable governmental authorities in Canada.

[1] NERC has been certified by the Commission as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*,116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[2] 16 U.S.C. 824o.

## II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on the Commission's service list are indicated with an asterisk.

## III. BACKGROUND

### a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory reliability standards, subject to Commission approval. Section 215 states that all users, owners and operators of the bulk power system in the United States will be subject to the Commission-approved reliability standards.

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005 (to be codified at 16 U.S.C. § 824o).

### b. Basis for Approval of Proposed Reliability Standard

Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each reliability standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a reliability standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve and enforce mandatory reliability standards, the Commission is authorized to approve those proposed reliability standards that meet the criteria detailed by Congress:

> The Commission may approve, by rule or order, a proposed Reliability Standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

When evaluating proposed reliability standards, the Commission is expected to give "due weight" to the technical expertise of the ERO. Order No. 672 provides guidance on the factors the Commission will consider when determining whether proposed reliability standards meet the statutory criteria.[5]

### c. Reliability Standards Development Procedure

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules

[4] Section 215(d)(2) of the FPA, to be codified at 16 U.S.C. § 824o(d)(2) (2000).
[5] *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* FERC Stats. & Regs., ¶ 31,204 at PP 320-36 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing reliability standards and thus satisfies certain of the criteria for approving reliability standards.[6]

The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standard set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and it was approved by the NERC Board of Trustees on February 12, 2008 for filing with the Commission.

The proposed reliability standard is accompanied by a document entitled "PRC-023 Reference – Determination and Application of Practical Relaying Loadability Ratings." This document is set out in **Exhibit D**, and presents the rationale behind the requirements in the proposed reliability standard as well as providing the calculation methodology to assist entities in application of the proposed reliability standard. This reference document is presented for information only and NERC is not requesting the Commission to take action on it.

**d. Progress in Improving Proposed Reliability Standards**

NERC continues to develop new and revised reliability standards that address the issues NERC identified in its initial filing of proposed reliability standards in April 2006, the concerns noted in the Commission Staff Report issued on May 11, 2006, and the directives the Commission included in several orders pertaining to NERC's reliability

[6] Order No. 672 at PP 268, 270.

standards.[7] NERC has incorporated these activities into its *Reliability Standards Development Plan: 2008-2010* that was submitted to the Commission on October 5, 2007. The reliability standard proposed for approval is a new reliability standard that addresses a key reliability goal that was not directly subject to Commission or staff review during NERC's filings of its reliability standards. Further, since the proposed reliability standard is completed and approved, it is not included in NERC's standards development work plan.

## IV. JUSTIFICATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD

This section summarizes the development of the proposed reliability standard and provides evidence that the proposed reliability standard meets the criteria for approval set by the Commission, that is, the proposed reliability standard is just, reasonable, not unduly discriminatory or preferential and in the public interest. This section describes the reliability objectives to be achieved by approving the reliability standard and how the reliability standard meets the criteria the Commission has established. The following section describes the stakeholder ballot results and how key issues were considered and addressed by the standard drafting team.

The complete development record for the proposed reliability standard is available in **Exhibit C.** This record includes the successive drafts of the reliability standard, the implementation plan, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the development of the

[7] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (2007) ("Order No. 693"), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 ("Order No. 693-A") (2007).

reliability standard, and how those comments were considered in developing the reliability standard. The standard drafting team roster is provided in **Exhibit B**.

**a. Basis and Purpose of PRC-023-1 — Transmission Relay Loadability**

The purpose of the standard is to set protective relays so as not to limit transmission loadability or interfere with system operators' ability to protect system reliability. At the same time transmission system protective relays must also be set to reliably detect and protect the electrical network from all fault conditions. The development of the PRC-023-1 — Transmission Relay Loadability Reliability Standard is a significant step toward improving the reliability of the bulk power system in North America because it addresses key August 14, 2003 blackout recommendations[8] regarding relay loadability issues.

Relay loadability refers to the ability of protective relays to restrain operation for load conditions. As protective relays can respond only to measured voltage and current, they must be set such that they will detect the faults for which they must operate while not operating unnecessarily for non-fault load conditions. This reliability standard requires certain Transmission Owners, Generator Owners and Distribution Providers to set protective relays to prescribed limits for the purpose of protecting systems and ensuring settings do not contribute to cascading outages, and to establish agreements with Planning Coordinators with respect to which transmission lines operated from 100 kV to 200 kV are subject to this new standard. Specifically, the protective relays should detect

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[8] U.S. – Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations – April 2004; NERC Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn? – July 13, 2004.

all fault[9] conditions, not limit transmission loadability, thus allowing system operators the flexibility and time to help maintain system reliability.

Relay loadability issues were found to have played a pivotal role in accelerating and spreading the early part of the cascading outage in Ohio and Michigan during the August 14, 2003 blackout and protective relay issues have exacerbated system disturbances at least since the Northeast Blackout of 1965. During the 2003 blackout, a substantial number of lines tripped due to relay loadability,[10] many of them before the blackout entered an unrecoverable cascading stage. It is difficult to be certain about the effect that this proposed reliability standard would have had on the end-state of the blackout. Considered in concert with other activities that have been precipitated by the blackout investigation, it seems clear that the events of the blackout would have taken a very different course and that relay loadability would not have been as pivotal a factor as seen on August 14, 2003.

This proposed standard specifically addresses Recommendation 8A[11] approved by the NERC Board of Trustees in February 2004, and the U.S.-Canada Power System Outage Task Force's Recommendation 21A, "Make More Effective and Wider Use of System Protection Measures,"[12] as included in the U.S.-Canada Power System Outage Task Force's April 2004 final report.

NERC Recommendation 8a specifically states,

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[9] A fault is an event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.

[10] Some notable examples of protective relays tripping due in inadequate relay loadability on August 14, 2003 include the Sammis-Star 345 kV line at 16:05:57 hours, and the Argenta-Battle Creek, Argenta-Tompkins, and Battle Creek-Oneida 345 kV lines at 16:10:36 hours. Many other lines also tripped due to similar causes.

[11] "August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts."

[12] "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendation."

> All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions[]. In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.

U.S. Canada Power System Outage Task Force Recommendation 21a specifically added:

> Task Force: Recommends that NERC broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces. Transmission owners should also look for zone 2 relays set to operate line zone 3s.

Although the U.S.-Canada Power System Outage Task Force focused on the role played by “zone 3” relays, it was later discovered that other phase-distance and overcurrent relays also contributed to the cascade. As a result this proposed standard extends beyond “zone 3” relays to include these load-responsive relays such as phase-distance and overcurrent relays.

The proposed reliability standard proposes three primary requirements summarized as follows:

R1. Requirement R1 including sub-requirements R1.1 through R1.13 outline criteria to be used for the setting of phase protective relays to prevent the relays from limiting transmission system loadability and remain responsive for all fault conditions. The sub-requirements are specific criterion to be used for certain transmission system configurations, to account for the presence of devices such as series capacitors, or to address thermal circuit capability. These criteria reflect the maximum circuit loading for the various system configurations and permit the relays to be set for optimum protection while carrying that load. Each criterion seeks to balance the need to protect the system while not limiting load carrying capability. These system configurations and conditions dictate which criterion is to be applied.

- The first criterion specifies transmission line relay settings based on the highest seasonal Facility Rating using the 4 hour thermal rating of a transmission line, plus a design margin of 150%.
- The second criterion may used in instances when detailed studies have been performed to establish the highest seasonal Facility Rating based on a 15-minute thermal rating of a transmission line. In these instances, a design margin of 115% is to be used.
- The third criterion may be used where the maximum theoretical power transfer limit across a transmission line reflects the maximum circuit loading capability. R1.3 offers two calculation methods for determining power transfer in cases of zero source impedance and in cases with known source impedances at each end of the transmission line,
- The fourth criterion may be applied where series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow

that protective relays must accommodate on series compensated transmission lines.

- The fifth criterion is applicable in cases where the maximum end-of-line three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines and the topology of the transmission system.
- The sixth criterion, R1.6, may be used for system configurations that have generation remote to load busses or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center.
- The seventh criterion, R1.7, is appropriate for some system configurations that have load centers which are remote from the generation center and where, under no contingency, would there be appreciable current flow from the load centers to the generation center.
- The eighth criterion, R1.8, is applicable to some system configurations that have one or more transmission lines connecting a remote, net importing load center to the rest of the system. Under these conditions, the total load in the remote area is the maximum load flow towards the load center.
- The ninth criterion, R1.9, applies to some system configurations that have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. Under these

conditions, the remote area will be able to supply limited load flow towards the system.

- The tenth criterion, R1.10, is specific to transmission transformer fault protective relays. The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally be sustained for several minutes without damage or appreciable loss of life to the transformer.
- The eleventh criterion, R1.11, may be used for those situations where the consequence of a transmission transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer. In these cases additional considerations are specified to limit unnecessary tripping due to load.
- The twelfth criterion, R1.12, is useful in cases of long line relay loadability where there are: only two lines; or where there are three or more terminal lines with one or more radial taps. In these cases, the relays must be set to provide minimum protection for a line, and the relay settings will limit the circuit loading capability. This limited circuit loading capability will become the Facility Rating of the circuit.
- The last criterion, R1.13, is intended to apply where otherwise supportable, practical conditions imposed by the previous sub-

requirements R1.1 through R1.12 are not suitable. For example, use of zone-3 relays for full backup protection of a particular line in the event of a breaker failure condition may utilize sub-requirement R1.13 to guide the settings. R1.13 can apply provided that extensive planning studies determine that the maximum load (even under Category 4 "Extreme" contingencies from TPL standards – Table 1) with a margin of 115% as specified in sub-requirement R1.13 does not conflict with those relay settings. As noted in R2, the entity must obtain the agreement of the Planning Coordinator, the Reliability Coordinator, and the Transmission Operator with the calculated circuit capability.

R2. Transmission Owners, Generator Owners, and Distribution Providers that use a circuit with phase protective relays settings per Requirements R1.6 through R1.9, R1.12 or R1.13, must calculate the circuit capability according to this requirement and reach agreement regarding the calculated circuit capability with the associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. Criteria R1.6 through R1.9 pertain to various transmission system configurations such as generation centers that are remote to load centers; load centers that are remote from generation centers; *etc.*, criterion R1.12 deals with long line relay loadability, and R1.13 deals with other circuit limitations not explicitly covered by R1.6 through R1.9 and R1.12. These requirements reflect specific system arrangements that present practical limitations to the maximum available load flow, and usually must be developed via calculation. However, when these practical limitations are used, the drafting team considered that all relevant operating entities must be in agreement that they have been accurately evaluated. When a Transmission Owner, Generator Owner or Distribution Provider selects and applies a circuit capability from any of the criteria listed in Requirement R2, these entities must then designate that circuit capability as the Facility Rating and obtain concurrence from its Planning Coordinator, Transmission Operator and Reliability Coordinator that they will respect that Facility Rating.

R3. Requirements R1 and R2 are to be applied to all transmission lines operated at 200 kV and above without exception. For lines operated from 100 kV up to 200 kV, Requirement R3 states that Planning Coordinators must designate the lines critical to the reliability of the Bulk Electric System to have Requirements R1 and R2 apply. Further, Requirement R3 states the Planning Coordinator shall have a process to determine which facilities operated between 100 kV and 200 kV are critical to the reliability of the Bulk Electric System, maintain a list of such facilities and provide the list to its Reliability Coordinators, Transmission Owners, Generator Owners and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

**Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest**

In Order No. 672, the Commission identified a number of criteria it will use to analyze reliability standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed reliability standards have met or exceeded the criteria:

**1. Proposed Reliability Standards must be designed to achieve a specified reliability goal**

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Proposed reliability standard PRC-023-01 — Transmission Relay Loadability specifically establishes, within Requirement R1 and its sub-requirements, that protective relay settings, while providing essential facility protection for faults, must not prevent the bulk power system from being operated in accordance with the established Facility Ratings as defined in NERC's Glossary of Terms. The proposed standard also establishes in Requirement R1.12 that in the event an essential fault protection imposes a more-constraining limit on the system, the limit imposed by the fault protection is reflected within the Facility Rating. A transmission system with protective phase relays set in accordance to this proposed Standard will have set the loadability envelope as far as is prudent and optimal. Said another way, relays that are set more conservatively than necessary will not afford system operators the maximum loadability of the transmission system under their control and as a consequence reduces the reaction time window needlessly.  Therefore, the criteria offered in this proposed reliability standard set an appropriate balance between prudent relay application and operator flexibility.

Proposed reliability standard PRC-023-1 interacts with several other NERC reliability standards to address the goal stated above.

**a)** NERC reliability standard FAC-008-1 – Facility Ratings Methodology requires that Transmission Owners and Generator Owners have a Facility Ratings methodology.  Proposed reliability standard PRC-023-1 establishes in Requirement R1.12 that, when protective relay loadability imposes a limit on the Facility Ratings, the resulting relay loadability is to be reflected in those Facility Ratings.

**b)** NERC reliability standard FAC-009-1 – Establish and Communicate Facility Ratings requires that Transmission Owners and Generator Owners establish Facility Ratings for their equipment, and that they provide those ratings to other affected entities.

**c)** NERC reliability standard IRO-002-1 – Reliability Coordination – Facilities requires that Reliability Coordinators shall have sufficient monitoring for the system within their Reliability Coordinator area to ensure that potential or actual System Operating Limit or Interconnected Reliability Operating Limits are identified, and that they monitor those elements.

**d)** NERC reliability standard IRO-005-1 – Reliability Coordination – Current Day Operations requires that Reliability Coordinators be aware at all times of the current state of the interconnected system (including all pre-contingency element conditions), be aware of all post-contingency element conditions, and have mitigation plans to alleviate System Operating Limit or Interconnected Reliability Operating Limit violations.

**e)** NERC reliability standard TOP-008-1 – Response to Transmission Limit Violations requires that Transmission Operators operate their systems such that System Operating Limit and Interconnected Reliability Operating Limit violations do not occur, and that, if they do occur, take immediate steps to alleviate the conditions causing the violations.

The interactions of the proposed reliability standard PRC-023-1 and the cited standards require that limits shall be established for all system elements, that the interconnected system shall be operated within those limits, that the operators shall take immediate action to mitigate operation outside those limits, and that protective relays (whether zone-3 protective functions or other load-responsive functions) shall not operate until the observed condition on their protected element exceeds those limits. The protective relay margins vary with individual sub-requirements and the various criteria as noted within R1.

**2. Proposed Reliability Standards must contain a technically sound method to achieve the goal**

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where

> appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed reliability standard contains technically sound methods to achieve the goal. The technical methodology was developed by a large team comprised of protective relaying subject-matter experts, was vetted through the IEEE Power System Relaying Committee (which is an even larger subject-matter-expert group in this area), and have been validated by over three years of industry application.

The development of this methodology started with the criteria suggested in NERC Recommendation 8a and evaluated conditions where the relay settings limited the operating capability of certain circuits although that limitation was not expressly known by the operators.

Therefore, the proposed standard defines specific technical criteria for a variety of configurations and circumstances that direct the minimum acceptable thresholds for relay settings so as not to impede the full operating capability of the circuit. Where circumstances indicate that a relay setting must necessarily limit the operation of the equipment, this limitation must be noted for consideration in the facility rating methodology.

After NERC's System Protection and Control Task Force ("SPCTF") developed the initial methodology for circuits 200 kV and above (zone-3 relays only), the methodology was applied to 10,914 total circuit terminals across North America, whereupon it was determined that 1,855 of those terminals required modification in order to conform to the criteria. After the methodology was enhanced to address other load-responsive relays other than zone 3, an additional 11,499 circuit terminals were reviewed, and 2,293 of those required modification. At this time, all of the terminals requiring modification as a result of the initial review have been addressed, and the vast majority of the terminals requiring modification due to the second-phase review have also been addressed.

Additionally, the proposed standard is rooted in part from lessons learned from investigations into many actual operating incidents based on the goal to minimize future contribution of protective relaying to system events.

**3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others**

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed reliability standard is applicable to users, owners and operators of the bulk power system, and not others. The entities include Transmission Owners, Generator Owners, Distribution Providers and Planning Coordinators that are users, owners and operators of the bulk power system.

NERC's SPCTF and the PRC-023 Standard Drafting Team recognized that the definition of "Bulk Electric System," varies throughout the eight Regional Entities. The SPCTF and the drafting team both concluded that this proposed reliability standard should be voltage-level-specific, as opposed to being generically applicable to the bulk electric system. This conclusion was reached by considering the potential variances in the facilities included as the bulk power system in different Regional Entities, together with an observation that the effects of the proposed reliability standard are not constrained to Regional boundaries. For example, if one Region has a purely performance-based criteria and an adjoining Region has a voltage-based criteria, these criteria may not permit consideration of the effects of protective relay operation in one Region upon the behavior of facilities in the adjoining Region.

On this issue, the standard drafting team also considered that the unilateral imposition of these requirements upon all 100 kV and above circuits, as suggested by the NERC general definition of the Bulk Electric System and by the definitions of several of the Regional Entities, would establish an increase of the implementation costs by approximately two orders of magnitude above those endemic in the proposed standard as drafted, and that this cost increase would distract financial, analytical and staffing resources from other areas with a higher effect on reliability. Subjecting such circuits to this Standard (absent determination of criticality as established in the requirements) would have little additional benefit to the reliability of the interconnected system.

The standard drafting team, when considering these factors, decided that the system applicability should be to all 200 kV and above circuits, and those lower voltage level circuits that are specifically determined to be critical to the reliability of the bulk electric system.

**4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply**

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed reliability standard is clear and unambiguous as to what is required and who is required to comply. Each requirement clearly states what applicable entities are required to do. Within the reliability standard, Requirement R1 requires that each relevant entity with Bulk Electric System equipment as defined in the applicability section shall maintain reliable protection and shall also set each of their protective relays according to one of the criteria established in the sub-requirements to Requirement R1. Requirement R2 establishes that, if a criterion pertains to a limitation other than the thermal rating of the specific circuit, the Planning Coordinator, Transmission Operator and Reliability Coordinator shall agree with the circuit capability used, and that that circuit capability shall be used as the Facility Rating of the circuit. Requirement R3 establishes that the Planning Coordinator shall have a methodology to determine "critical" 100-200 kV circuits, that they shall maintain a list of circuits determined using that methodology, and that they shall provide the list to the relevant entities for application of Requirement R1.

All the requirements provide additional specificity regarding the setting of protective relays as related to various practical circuit capabilities. Those requirements which refer to study-based system conditions, rather than established Facility Ratings, require that system flows be carefully evaluated by the wide-area operating entities (Reliability Coordinators), local area operating entities (Transmission Operator) and wide-area planning entities (Planning Coordinators) to assure that no flow which the interconnected system can withstand, will result in protective relay operation due to load currents encroaching the active reach of a load-responsive relay, and that those entities agree with those conditions.

**5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**

Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed reliability standard includes clear and understandable consequences and a range of penalties for a violation. Each primary requirement is assigned a Violation Risk Factor and the standard includes Violation Severity Levels that contain detailed descriptions of noncompliance for each requirement that correspond to the Lower, Moderate, High and Severe assignments as described in the Sanction Guidelines. These elements will support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in Commission-approved standards, as defined in the ERO Sanction Guidelines.

Requirement R1 is assigned a High Violation Risk Factor in accordance with the definition set forth in the ERO Sanction Guidelines where non-compliance of the requirement can "directly cause or contribute… to a cascading sequence of failures…." The assignment of a Medium Violation Risk Factor to Requirements R2 and R3 reflect the lesser probability of impact to the bulk power system resulting from non-compliance.

**6. Proposed Reliability Standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed reliability standard identifies clear and objective criterion or measures for compliance, so that that the standard can be enforced in a consistent and non-preferential manner. Each requirement clearly states mathematical formulas for transmission relay settings, required agreements, and a process for and the identification of critical assets with respect to transmission relay loadability such that the respective applicable entities know what is required to achieve the reliability objective. The simplest example may be found in R1.1, which states "Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes)." All other R1 sub-requirements have similarly specific requirements which relate to the practical circuit capability represented in the sub-requirement. The measures clearly correspond to each required settings, agreement and facility process and identifications for their respective requirements such that each requirement can clearly and consistently be enforced without prejudice to any party. The three measures are included in Section C of the proposed reliability standard.

Furthermore, to aid in the compliance monitoring process, NERC will develop a reliability standard audit worksheet ("RSAW") for this reliability standard if the standard is included in the list of actively monitored reliability standards for a particular program year. As these RSAWs are guides for compliance auditors, they may also assist the entity in understanding what they are expected to provide in support of the particular measures to demonstrate compliance.

**7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost**

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed reliability standard achieves its reliability goal effectively and efficiently, without necessarily having to reflect "best practices" without regard to implementation costs. In many cases, entities may comply with the proposed reliability standard by using long-established calculation methods that have been applied to legacy equipment, and therefore the proposed standard does not require the use of the latest available technology, nor does it require the use of any evolving best-practice evaluation methods.

In many cases, the calculation methods will determine whether legacy equipment can be adjusted to meet the proposed reliability standard. In some cases, however, recent advancements in protective relay technology will be needed to satisfy the requirements of the proposed reliability standard and also provide effective fault protection for the relevant system element. For example, the protection of circuits above 200 kV is considerably demanding of the most sophisticated protective relays; therefore, it is customary that most modern protective relays are applied to circuits above 200 kV. Lower voltage circuits usually require less-sophisticated protective relays to satisfy the protective criteria; thus, the applied relays do not require and thus may not have the advanced capabilities noted above. Additionally, communications-based relaying, which can detect faults over the entire length of a circuit as well as provide communications-based backup protection (rather than backup protection based on overreaching distance relays) is much more common at 200 kV and above, and the substation bus arrangements at 200 kV and above diminish the need for relaying at remote locations that will detect faults in the event of protective equipment failure. These factors all contributed to the decision to limit universal applicability to circuits 200 kV and above, and to make the reliability standard applicable only to 100-200 kV circuits that are “critical” to the reliability of the bulk power system.

**8. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability**

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

The proposed reliability standard is not a "lowest common denominator," and does not reflect a compromise that fails to adequately protect bulk power system reliability. The proposed standard establishes a first-ever, challenging threshold through a set of minimum requirements that will considerably advance the formalization of preventative settings and operations of protective equipment. This will serve the important reliability goal of minimizing the contribution of protective relays to future system events. While these requirements are "minimum" requirements, they have been determined by careful analysis of Facility Ratings, and by review of practical System Operating Limits to establish base thresholds not in existence heretofore, and carefully balance those thresholds with the need to provide effective fault protection for the affected circuits.

Relay loadability has commonly played a significant role in system disturbances including the 1965 blackout and the August 2003 blackout. As a result of the NERC SPCTF-directed program, relay loadability has been a much lesser factor on the list of contributory factors for North American disturbances since August 2005.

Only two instances of relay loadability have been noted in event analyses since the relay loadability review was conducted: one was on a lower voltage transmission circuit that was not subject to the loadability review; and the other was on a circuit that had been scheduled for loadability mitigation in response to the relay loadability review program, but had not yet been corrected. The latter occurred during a contingency that impacted two large sister nuclear units that were each isolated to single 230 kV lines. One unit tripped on instability, but stability analysis showed that the second unit would not have tripped had the line not tripped due to relay loadability issues. The remote-end phase overcurrent relays were set below what the line would have to carry as a single outlet for the unit. Those relays had previously been determined to require setting changes to conform to the relay loadability review recommendations, but work was not scheduled until later in the year of the event. If the changes to the settings had been completed, the line would likely not have tripped and the second nuclear unit would not have tripped or experienced a loss of off-site power

**9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability**

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed reliability standard has considered costs to implement for smaller entities, but not at consequence of less then excellence in operating system reliability. Implementation costs related to the proposed reliability standard will be directly proportional to the amount of relevant facilities owned by the applicable entity. A smaller entity that owns, for example, 10 pertinent circuits will have far lower (approximately proportional) implementation costs that another that may own 100 or 1000 pertinent circuits. Further, entities that operate lower voltage bulk power system components below 200 kV are not held to the standard unless the facilities are determined to be critical to reliability.

**10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach**

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed reliability standard is designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach. The standard as drafted proposes no Regional differences or variances.

**11. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid**

> Order No. 672 at P 332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential

> manner. It should not create an undue advantage for one competitor over another.

The proposed reliability standard should cause no undue negative effect on competition or restrict the grid beyond that which is necessary for reliability, making it acceptable in regards to this factor. In some cases, this proposed standard actually serves to remove arbitrary relay limitations that cause transmission capability limitations. With the exception of those relays that legitimately define and therefore restrict the facility rating, this standard removes capricious limits related to relay loadability. Further, no market-based entity is required to comply with this standard.

**12. The implementation time for the proposed Reliability Standards must be reasonable.**

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The implementation plan for the proposed reliability standard indicates that the reliability standard is to become effective the first day of the quarter no sooner than fifteen months after regulatory approval by the Commission. NERC believes this presents a reasonable time frame to allow all entities to be in compliance. The technical requirements of this standard have been implemented by most applicable entities starting in January 2005 under voluntary activities directed by the NERC Planning Committee. Most entities have provided assurances to NERC that they have implemented these technical requirements. The implementation period established in the Implementation Plan provides an opportunity for those entities which did not participate in the voluntary activities to comply with the proposed reliability standard, and for all entities to establish the documentation necessary to demonstrate compliance.

**13. The Reliability Standard development process must be open and fair**

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission.

NERC develops reliability standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure*, which was incorporated into the Rules of Procedure as Appendix 3A. In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness and a balance of interests in developing reliability standards.[13] The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a reliability standard for submission to the Commission.

The proposed reliability standard set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*, and was approved by the NERC Board of Trustees on February 12, 2008 for

[13] Order No. 672 at PP 268, 270.

filing with the Commission. Therefore, NERC has utilized its standard development process in good faith and in a manner that is open and fair.

**14. Proposed Reliability Standards must balance with other vital public interests**

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

The proposed reliability standard establishes a technical balance between established Facility Ratings and protective relay performance. No environmental, social, or other goals are reflected, nor do they enter into consideration, apart from ensuring the reliability of the grid through removal of unnecessary limitations on grid performance due to load-responsive relays.

**15. Proposed Reliability Standards must consider any other relevant factors**

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.
>
> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

NERC does not propose any additional factors for consideration at this time.

## V. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

### a. Development History

On January 9, 2006, the NERC SPCTF submitted a Standards Authorization Request ("SAR") to address the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase[14] protective relays operated on high line loading and low voltage without electrical faults on the protected lines. The SAR addresses in part a key NERC recommendation from the 2003 Blackout, "Improve System Protection to Slow or Limit the Spread of Future Cascading Outages," which underscores the culpable role of relay loadability in that disturbance. Similarly, the U.S.-Canada Power System Analysis Task Force referred to the impact of relay loadability upon major transmission system disturbances in its August 2003 Blackout report recommendation 21a (JTF 21a). In March 2004, the NERC Planning Committee assembled a SPCTF to focus on zone 3[15] relays, their merits, deficiencies, current usage, setting parameters and to recommend relay protection design improvements in the prevention and mitigation of cascading failures.

The SAR was posted for a 30-day comment from January 16, 2006 through February 15, 2006. There were 17 sets of comments, including comments from 64 different people from 41 companies representing 6 of the 10 industry segments in the

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[14] The original NERC and U.S. Canada Power System Outage Task Force recommendations referred to "Zone 3" and "Zone 2" relays, which are specifically relays which respond to calculated impedance, which equates to distance. The proposed Reliability Standard also acknowledges that other "phase" relays respond to load conditions. In contrast, "ground" relays respond only to unbalanced conditions which are indicative of ground fault conditions, and do not respond to load conditions.

[15] "Zone 3" relays refer to impedance, or distance, relays which are set to respond to fault conditions well beyond the remote end of the line, and which do so without requiring communications from the remote terminal. These relays are considered to be those most responsive to load conditions.

Registered Ballot Body. A technical reference document prepared by the SPCTF included the analytical work that underpinned the SAR and was posted with the standard. All comments were addressed and the SAR was modified in response to the comments. The drafting team posted its consideration of the comments on April 26, 2006.

On May 12, 2006, the Standards Committee authorized advancing the SAR to standards development. The standard drafting team consisted of 11 members with system protection engineering, transmission planning or transmission system consulting backgrounds. Drafting team members represent the interests of the large transmission owners, distribution provider organizations, and ISO/RTOs. Three successive versions of the draft standard were posted for public comment, resulting in a final draft that proceeded to the balloting stage.

***Draft 1:*** NERC posted the initial draft of the proposed standard for a 45-day comment period from August 16, 2006 through September 29, 2006. NERC received 36 sets of comments from more than 100 different persons representing over 50 companies from 6 of 10 segments. The team modified the standard in response to comments on the initial draft and posted its Consideration of Comments report[16] January 9, 2007.

***Draft 2:*** NERC posted the second draft of the proposed standard for a 30-day comment period from January 9 through February 7, 2007. There were 22 sets of comments, including comments of more than 93 different people from more than 66 companies representing 9 of the 10 Industry Segments. The team modified the standard in response to these comments and posted its Consideration of Comments report[17] March 9, 2007.

[16] *See* Exhibit C item # 17.
[17] *See* Exhibit C item # 26.

***Draft 3:*** NERC posted the third draft of the proposed standard for a 30-day comment period from March 19 through April 17, 2007. There were 14 sets of comments, including comments of more than 49 different people from more than 40 companies representing 8 of the 10 Industry Segments. The drafting team modified the standard in response to these comments as well.

In addition to stakeholder comments received on the third draft, the Commission staff met with NERC staff and some members of the drafting team in May 2007 to informally discuss the proposed reliability standard. As a result of this meeting and subsequent discussion with Commission staff, NERC requested the drafting team to consider several issues to include in the drafted standard. As there was no established process for consideration of Commission staff input apart from the reliability standards development process, NERC's Standards Committee directed that if the drafting team did determine that it wished to make changes as a result of this input, the team would be required to present the modified standard for a minimum 30-day industry comment period. In doing so, the Standards Committee agreed that consideration of this input was valuable to achieving a favorable outcome when the proposed standard was ultimately filed for approval. The drafting team met and discussed observations of Commission staff, and made certain changes to the standard, discussed in the *Key Issues* section below. However, the team did not consider the changes made to be significant and thus did not request that the drafted standard be publicly posted for comment.

All the comments and the team's consideration of these comments were incorporated into a revised Consideration of Comments report to the third posting of the standard.[18] On October 11, 2007 the Standard authorized advancing the standard to balloting. The summary of the balloting stage of the proposed standard follow.

***Pre-Ballot Review:*** After the drafting team considered and responded to the comments received during the third public comment period, NERC posted the final draft of the proposed standard for a 30-day pre-ballot review from October 18, 2007 through November 19, 2007.

***First Ballot:*** The initial ballot of the drafted standard was conducted from November 19, 2007 through December 4, 2007. During the first ballot, 91.83% of those registered for the ballot pool voted, which exceeded the minimum 75% quorum required to be a valid vote. The proposed reliability standard received a weighted segment approval of 80.84%. However, there were 37 negative ballots submitted with 23 of those negative ballots submitting a comment, triggering the need for a recirculation ballot.

Some commenters raised issue with regard to the threshold used to define the applicability of facilities subject to the requirements in this standard. Most stakeholders agreed with the applicability of the proposed standard. The standard drafting team acknowledged that the threshold may not be unanimously supported, while asserting it is an acceptable "starting point" for the application of this new set of requirements.

Several commenters suggested that the word, "critical" should not be used in the standard. The standard drafting team deliberately avoided capitalizing the word, "critical" in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, "Critical Asset." When a word is not capitalized in a NERC

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[18] *See* Exhibit C item # 34.

standard, the word is not a NERC-defined term and has the same meaning as that found in any collegiate dictionary.

In addition, several typographical and editorial changes were made to the standard in response to the initial ballot comments; however, the changes did not alter the technical content of the standard nor did they change the content or intent of any of the requirements or compliance elements of the standard.

***Recirculation Ballot:*** After the standard drafting team responded to the comments, the proposed reliability standard proceeded to a recirculation ballot that was conducted from January 31, 2008 through February 9, 2008. The proposed reliability standard passed with a final quorum of 93.27% and a weighted segment approval of 82.64%. A two-thirds weighted segment approval is required for passage. On February 12, 2008, the NERC Board of Trustees adopted the proposed reliability standard.

**b. Key Issues**

During the development of the proposed reliability standard, the standard drafting team considered several key issues that are discussed in this section: i) the scope of the proposed standard, ii) implementation dates, iii) incorporating Commission comments, iv) bulk power system definition, and v) applicability of Requirement R3 and field testing.

**<u>i) THE SCOPE OF THE PROPOSED STANDARD</u>**

A technical reference document was initially developed by subject matter experts in response to the NERC Blackout Recommendation 8a and the Blackout Task Force Recommendation 21A. The technical reference document titled, "PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings" was posted with the SAR during the 30-day comment from January 16, 2006 through February 15, 2006. The document includes the analytical work that underpinned the SAR and provided explanatory text and supplemental material. The work scope as contained in the SAR for this project was formed on the basis of the technical reference document. The subsequent technical scope of this standard was refined through the stakeholder comment process provided during SAR development, standard drafting, and ballot comment periods.

The purpose of the reference document is to aid entities in understanding the requirements within PRC-023-1. This reference document is not intended to present additional requirements and should not be construed to do so, even though some of the text may appear to be prescriptive. In accordance with the *Reliability Standards Development Procedure*, reference documents may explain or facilitate implementation of a standard but do not contain mandatory requirements subject to compliance review.

**ii) IMPLEMENTATION DATES**

Some commenters stated that the proposed effective dates were overly ambitious. There are, however, current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due dates for these activities were December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities. A review of the industry responses to the ongoing activities indicates that most, if not all, affected responsible entities have already performed the bulk of the work needed to comply with the proposed Standard and therefore, the comments offered lacked a sufficient basis.

### iii) INCORPORATING COMMISSION COMMENTS

In addition to stakeholder comments for the third draft of the proposed standard, the Commission staff invited NERC and the drafting team to an informal meeting to discuss the Standard. A subgroup of the larger drafting team, along with members of NERC staff, presented an overview and technical highlights of the proposed Standard in May 2007.

Shortly after the presentation meeting, the Commission staff indicated there were additional points of clarification and explanation desired and suggested changes were brought forward to the drafting team for consideration. Following the closing of the then-open comment period, the drafting team met and discussed observations of Commission staff, and made the following changes to the standard, either in support of the observations, to improve the clarity of the standard, or to better support the compliance program:

- Revised the purpose statement to include stronger emphasis on the reliability objective behind this standard.
- To simplify compliance enforcement, revised the proposed effective dates to ensure that all requirements become effective on the first day of a calendar quarter and to reflect that in some jurisdictions, the approval of a standard is tied to Board of Trustees' adoption and not a separate regulatory approval.
- Inserted the phrase "load-responsive" into Sections A.4.1, A.4.2 and A.4.3 of the proposed standard for clarification.

- The Commission expressed a concern that 15-minute ratings may be used that are not completely reflected as Facility Ratings. The drafting team modified the second footnote to clarify that Requirement R1.2 references 15-minute ratings where such ratings have been calculated and are used for real-time operations.
- Added a third footnote to Requirement R1.11 to reference the IEEE standard that supports the requirement.
- In the third comment posting, Requirement R4 contained a combination of requirement language and implementation plan language, that is, it expressed both an implementation schedule for compliance with Requirement R1 for the initial "critical" 100-200 kV circuits, and also established a requirement for when the responsible entity would be required to be in compliance for additional circuits added to the list. The text related to implementation schedules was entirely relocated to Section 5, Effective Dates in the standard.
- Replaced the term Regional Entity with Compliance Enforcement Authority in Section D.
- Modified the Violation Severity Levels to include a reference to the associated requirement.

In addition, the Commission staff offered additional observations that were fully considered by the drafting team and NERC, but were not included in the balloted standard. These issues are discussed below.

Generator step-up ("GSU") transformer relay loadability was intentionally omitted from PRC-023. GSU relay loadability merits particular attention in the area of generator protection, and as such, it would be inappropriate to include in a transmission relay loadability standard without consideration of the overall generator protective systems in place. It is imperative that GSU protection settings be coordinated with other generator protection functions as well as the associated local transmission system protection. That includes careful consideration of the transient, sub-transient, and steady state generator responses to system conditions, and how the resultant loadings on the GSU must be considered in loadability. Further, from a process perspective, the standard drafting team did not have the requisite technical expertise from representatives from the generator industry segment on the team. Therefore, additional members would need to be identified and added, and then given time to develop the generator protection requirements which would have delayed the presentation of the proposed standard by at least six months. In lieu of delaying a quality standard pertaining to the transmission relay loadability, NERC elected to push forward with this proposed standard and address generator protection standards for relay loadability in future development efforts.

The NERC SPCTF is working closely with the IEEE Power System Relay Committee ("PSRC") and its rotating machinery subcommittee to prepare the necessary technical basis for a separate generation protection standard. Once the technical foundation is developed, GSU relay loadability will be then included in a future standards development activity. NERC expects that this effort will begin in 2009.

Commission staff questioned whether zone 3 relays should be available for use on the Bulk Power System at all. On this matter, the proposed reliability standard is silent.

The proposed reliability standard establishes requirements for any load-responsive relay on the applicable system elements, regardless of the protective functions being served. The SPCTF paper, "Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems, *A Report on the Implications and Uses of Zone 3 Relays,*" addresses the advantages, disadvantages and appropriate application of Zone 3 Relays at length.

Commission staff also indicated a desire for the proposed standard to address the issue of power swings that encroach on the load-responsive relay operational zone.

To consider the concerns about responsiveness of protective relays to power swings, it is necessary to consider the relative time frames of system swings and faults, and to consider that this standard addresses the issues of loadability during a time frame when lines are overloaded and operators can take action. In the August 2003 blackout, the power swing time frame was too short a time frame in which an operator could have taken action, and this is typical for severe power swings. In the electrical vicinity of severe power swings, they are indistinguishable from faults, and it is clear that the relays must respond for faults.

**iv) BULK ELECTRIC SYSTEM DEFINITION**

Comments throughout development identified an issue related to the use of the term bulk electric system. The NERC Glossary of Term defines Bulk Electric System (bulk electric system) as follows: "(a)s defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." This definition clearly allows for Regional variations in the definition of bulk electric system, potentially among neighboring regions. NERC's recommendations from the investigation into the August 13, 2003 blackout, which provided the genesis for the work preceding the development of this proposed reliability standard, addressed relay loadability requirements for "transmission lines operating at 230 kV and above" (NERC Recommendation 8A) and later recommended in the Blackout Task Force report that "NERC broaden the review to include operationally significant 115 kV and 138 kV lines" (US-Canada Power System Outage Task Force Blackout Task Force Recommendation 21A). By specifically referring to voltage levels in the recommendations, these reports implicitly recognized that system response across the Eastern Interconnection was indifferent to the variations in the definition of the Bulk Electric System. The SPCTF initially, and later the standard drafting team, considered the that the blackout recommendations did not align precisely with the various definitions of Bulk Electric System and deferred to the approach detailed in the blackout recommendations. There were numerous stakeholder comments related to this issue.

The SPCTF (initially) and the drafting team both concluded that this proposed reliability standard should be voltage-level-specific, as opposed to being generically applicable to the bulk power system. This conclusion was reached by considering the potential variances in the facilities included as the bulk power system in different Regional Entities, together with an observation that the effects of the proposed reliability standard are not constrained to regional boundaries. For example, if one Region has a purely performance-based criteria and an adjoining Region has a voltage-based criteria, these criteria may not permit consideration of the effects of protective relay operation in one Region upon the behavior of facilities in the adjoining Region.

On this issue, the standard drafting team also considered that the unilateral imposition of these requirements upon all 100 kV and above circuits, as suggested by the NERC definition, would establish an increase of the implementation costs by approximately two orders of magnitude above those endemic in the draft Standard, and that this cost increase would distract financial, analytical and staffing resources from other areas with a higher effect on reliability. Subjecting such circuits to this Standard (absent determination of criticality as established in the requirements) would have little benefit to the reliability of the interconnected system.

The drafting team, when considering these factors, decided that the system applicability should be to all 200 kV and above circuits, and those lower-voltage-level circuits that are specifically determined to be critical to the reliability of the bulk power system. Although this position was consistent throughout the development of the proposed reliability standard, several commenters consistently offered comments opposing the established applicability, and suggested that the applicability should be limited to the circuits that are specifically determined to be critical to the reliability of the bulk electric system, regardless of voltage. It is recognized that the enforceability of this proposed standard is statutorily limited to such circuits as are also included in the definition of Bulk Electric System.

#### vi) APPLICABILITY FOR REQUIREMENT R3 AND FIELD TESTING

Based on the foregoing decision, the standard drafting team needed to identify which NERC functional entity was best suited to determine which circuits are critical to the reliability of the bulk power system below the 200 kV threshold. Because the Regional Entity is not a user, owner or operator of the bulk power system, the team could not assign requirements to them although they had served that role in the voluntary era of reliability standards. The drafting team carefully reviewed NERC's Functional Model and determined that the Planning Coordinator intended to have the wide-area view for the planning time horizon. As a result, the responsibility for determining the facilities critical to bulk power system reliability was assigned accordingly. Several drafts of the proposed standard were posted for comment with this assignment, and industry consensus appears to support this assignment.

Once the decision was made to assign responsibility for lower-voltage level critical circuits to the Planning Coordinator, the team then needed to determine whether field testing was needed, such that the function could be implemented by the Planning Coordinator as envisioned by the team. Commenters were split on the issue of whether field testing for the Planning Coordinator was needed. The need for field testing of this standard was evaluated by NERC's Compliance staff, by the Regional Entity Compliance Managers and by stakeholders. There was no consensus on the need for a field test and on October 11, 2007 the Standards Committee authorized moving the standard forward to ballot without a field test.

## VI. CONCLUSION

NERC requests that the Commission approve PRC-023-1 — Transmission Relay Loadability, as set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of the Commission's regulations. NERC requests that PRC-023-1 — Transmission Relay Loadability be made effective under the Commission's procedures in accordance with the implementation plan provided with the reliability standard.

Respectfully submitted,

*/s/ Rebecca J. Michael*

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## CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 30th day of July, 2008.

*/s/ Rebecca J. Michael*
Rebecca J. Michael

*Attorney for North American Electric Reliability Corporation*

# Exhibit A

## Reliability Standard PRC-023-1 submitted for approval

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability:**

**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

**5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

**5.2.** Requirement 3: 18 months following applicable regulatory approvals.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Compliance Enforcement Authority

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | February 12, 2008 | Approved by Board of Trustees | New |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**3.8.** Relay elements associated with DC lines.

**3.9.** Relay elements associated with DC converter transformers.

# Exhibit B

## Standard Drafting Team Roster

# Relay Loadability Drafting Team

| | | | |
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| | | | |
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# Exhibit C

# The complete development record of the proposed Reliability Standards

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Reliability Standards**

**Transmission Relay Loadability**

Registered Ballot Body | Related Files | Reliability Standards Home Page | Drafting Team Rosters

**Status**
The NERC Board of Trustees approved for adoption Reliability Standard PRC-023-1 on February 12, 2008.

**Purpose / Industry Need**
This proposed standard will address the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called 'zone 3 relay' issue, which has been expanded to address other protection devices subject to unintended operation during extreme system conditions. The standard will establish minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance. In December 2005, the Planning Committee approved a white paper providing the engineering basis for the proposed standard, culminating a major project to analyze the performance of existing protection systems and to research preferred set points.

| Proposed Standard | Supporting Materials | Comment Period | Comments Received | Response to Comments |
|---|---|---|---|---|
| Draft 6<br>Relay Loadability Standard<br>Posted for Board of Trustees Approval<br><br>PRC-023-1<br>Clean (55) \| Redline to initial ballot (56) | Implementation Plan<br><br>Reference Document<br><br>(Same as last Posting) | | | |
| Announcement (52)<br><br>Draft 5<br>Relay Loadability Standard<br>Posted for 10-day Ballot Recirculation Ballot Window<br><br>PRC-023-1<br>Clean (50) \| Redline | Implementation Plan<br><br>Reference Document<br><br>(Same as last Posting) | 01/31/08 - 02/09/08<br><br>Recirculation Ballot Window | | Announcement (53)<br><br>Ballot Summary (54) |

| Proposed Standard | Supporting Materials | Comment Period | Comments Received | Response to Comments |
|---|---|---|---|---|
| to initial ballot (51) | | | | |
| Announcement (43)<br><br>Draft 4<br>Relay Loadability Standard<br>Posted for 10-day Ballot Window<br><br>Clean (42) \| Redline to last posting (41) | Implementation Plan<br><br>Clean (44) \| Redline to last posting (45)<br><br>Reference Document (46) | 11/19/07 - 12/04/07 (closed)<br><br>10-day Ballot Window | | Announcement (47)<br><br>Ballot Summary (48)<br><br>Consideration of Comments (49) |
| Announcement (37)<br><br>Draft 4<br>Relay Loadability Standard<br>Posted for 30-day Pre-ballot Review<br><br>Clean (36) \| Redline to last posting (35) | Implementation Plan<br><br>Clean (38) \| Redline to last posting (39)<br><br>Reference Document (40) | 10/18/07 - 11/19/07 (closed)<br><br>Pre-ballot Review | | |
| Announcement (29)<br><br>Draft 3<br>Relay Loadability Standard<br>Posted for 30-day Comment Period March 19 through April 17, 2007<br><br>Clean (28) \| Redline to last posting (27) | Implementation Plan<br>Clean (30) \| Redline (31) | 03/19/07 - 04/17/07<br><br>Comment Form (32) | Comments (33) | Consideration of Comments (34)<br><br>Revised |
| Announcement (20)<br><br>Draft 2<br>Relay Loadability Standard<br>Posted for 30-day Comment Period January 9 through February 7, 2007<br><br>Clean (19) \| Redline to first posting (18) | Implementation Plan<br>Clean (21) \| Redline (22)<br><br>Relay Loadability Reference (23) | Comment Form (24)<br><br>12/09/07 - 02/07/07 (Ended) | Comments (25) | Consideration of Comments (26) |
| Announcement (12)<br><br>Draft 1<br><br>Relay Loadability Standard<br>Posted for 45-day | Implementation Plan (13)<br><br>Reference Document (14) | Comment Form (15)<br><br>08/16/06 - 09/29/06 (Ended) | Comments (16) | Consideration of Comments (17) |

| Proposed Standard | Supporting Materials | Comment Period | Comments Received | Response to Comments |
|---|---|---|---|---|
| Comment Period August 16 through September 29, 2006<br><br>Draft Standard Version 1 (11) | | | | |
| Draft 2<br><br>Draft SAR Version 2 – clean (10)<br><br>Draft SAR Version 2 – redline (9) | | | | |
| Announcement (7)<br><br>Solicit Drafting Team Members | | Nomination Form (8)<br>Due May 3, 2006 | | |
| Announcement (2)<br><br>Draft 1<br>Posted for Comment January 16-February 15, 2006<br><br>Draft SAR Version 1 (1) | Working Paper on Proposed Transmission Relay Loadability (3) | January 16, 2006 - February 15, 2006<br><br>Nomination Form (4)<br>Due February 3, 2006 | Comments (5) | Responses (6) |
| To download a file click on the file using your right mouse button, then save it to your computer in a directory of your choice. | | | | |
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**All comments should be forwarded to sarcomm@nerc.net.**
**Questions? Contact Barbara Bogenrief - barbara.bogenrief@nerc.net or 609-452-8060.**

E-mail completed form to mark.ladrow@nerc.net

# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Transmission Relay Loadability |
| Request Date | January 09, 2006 |

| **SAR Requester Information** | **SAR Type** (Check box for each one that applies.) | |
|---|---|---|
| Name NERC System Protection and Controls Task Force (SPCTF) | ☒ | New Standard |
| Primary Contact<br>Charles Rogers, Chairman of SPCTF | ☐ | Revision to existing Standard |
| Telephone (517) 788-0027<br>Fax (517) 788-0917 | ☐ | Withdrawal of existing Standard |
| E-mail cwrogers@cmsenergy.com | ☐ | Urgent Action |

Purpose/Industry Need

Protective relays have contributed to virtually all major system disturbances including the Northeast Blackout of 1965, the New York Blackout of 1977, the WECC Blackouts of 1996, and the Blackout of August 14, 2003. During the 2003 blackout, relay loadability was found to have played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by “zone 3” relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

As a result, recommendations were made for the review of relay settings and the mitigation of zone 3 relays operating under load included in NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.-Canada Power System Outage Task Force Recommendation 21a, *Make More Effective and Wider Use of System Protection Measures*.

Over the last 18 months, the electric industry has been reviewing protection systems to determine their conformance with the loadability criteria set forth in those recommendations. The monumental effort to review and mitigate relay loadability issues done by the industry is to be applauded. However, those improvements to the protection systems cannot be allowed to lapse if relay loadability problems are to cease to be an ongoing contributor to system disturbances.

It is imperative to the continued reliability of the North American power system that the problems of relay loadability remain corrected and that the technical solutions are properly codified in NERC reliability standards.

### *Reliability Functions*

| **The Standard will Apply to the Following Functions** *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Regional Reliability Organization | Ensures the reliability of the bulk electric system within its Region. |
| ☐ | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐ | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐ | Planning Authority | Plans the bulk electric system |
| ☐ | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐ | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☐ | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☒ | Transmission Owner | Owns transmission facilities |
| ☐ | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☒ | Distribution Provider | Provides and operates the “wires” between the transmission system and the customer |
| ☒ | Generator Owner | Owns and maintains generation unit(s) |
| ☐ | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐ | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐ | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐ | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

***Reliability and Market Interface Principles***

| **Applicable Reliability Principles** *(Check box for each one that applies..)* | |
|---|---|
| ☒ | 1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☐ | 3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☒ | 4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☒ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☒ | 7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
|---|
| 1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| 2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| 3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| 4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| 5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)**

**Scope**

The scope of the proposed standard would be to codify the relay loadability criteria and their implementation in accordance with the tenets of NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada *Power System Outage* Task Force Recommendation 21A, *Make More Effective And Wider Use Of System Protection Measures,* to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages.

**Applicability**

[Definition of Transmission Protection System Owners (TPSOs)
Entities that own and/or operate protective relaying systems applied to protect transmission facilities operated at 100 kV and above, including transformer banks with low-voltage terminals operated at 100 kV and above.]

1. This standard pertains to phase protection systems applied to:
    a. Transmission lines operated at 200 kV and above
    b. Transmission lines operated at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
    c. Transformers with low voltage terminals connected at 200 kV and above voltage levels
    d. Transformers with low voltage terminals connected at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
2. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
    a. Phase distance
    b. Out-of-step tripping
    c. Out-of-step blocking
    d. Switch-on-to-fault
    e. Overcurrent relays
    f. Communications aided protection schemes including but not limited to:
        i. Permissive overreach transfer trip (POTT)
        ii. Permissive under-reach transfer trip (PUTT)
        iii. Directional comparison blocking (DCB)
3. The following protection systems are excluded from requirements of this standard:
    a. Relay elements that are only enabled when other relays or associated systems fail.
        i. Overcurrent elements that are only enabled during loss of potential conditions.
        ii. Elements that are only enabled during a loss of communications.
    b. Protection systems intended for the detection of ground fault conditions

c. Protection systems intended for protection during stable power swings.
d. Generator protection relays that are susceptible to load.
e. Relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

4. This standard applies to the following entities:
    a. Regional Reliability Organizations.
    b. Transmission Owners that are Transmission Protection System Owners (TPSOs).
    c. Generation Owners that are TPSOs.
    d. Distribution Providers that are TPSOs.

The standard should incorporate relay loadability criteria for all phase distance (including zone 3) and overcurrent relays, as well as, any protective functions which could trip with or without time delay, on normal or emergency load current. The Standard should specifically exclude: relay elements that are only enabled when other relays or associated systems fail, protection systems intended for the detection of ground fault conditions, protection systems intended for protection during stable power swings, generator protection relays that are susceptible to load, relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

The proposed standard should consider that during emergency loading conditions on the transmission system, the system operators should be making the human decision to open overloaded facilities, if conditions so warrant. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion should be specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. The system operator actions may include manual removal of the transmission circuit from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).

**Additional Information**

The *Working Paper on a Proposed Transmission Relay Loadability Standard*, prepared by the System Protection and Controls Task Force includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. It is available on the NERC SPCTF website using the hotlink above. That working paper was prepared to assist the Standards Authorization Committee and its SAR and/or standards drafting team in the development of the proposed standard. This working paper takes full advantage of the recent experience of applying those criteria to the EHV transmission system (200 kV and above) and ongoing work on the 100–200 kV Operationally Significant Circuits.

Additional technical information can also be found in *EHV Transmission System Relay Loadability Review and Requests for Temporary and Technical Exceptions* report and *Protection System Review Program - Beyond Zone 3* report at the NERC website

## *Related Standards*

| Standard No. | Explanation |
|---|---|
| | |
| | |
| | |
| | |

## *Related SARs*

| SAR ID | Explanation |
|---|---|
| | |
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## *Regional Differences*

| Region | Explanation |
|---|---|
| ECAR | |
| ERCOT | |
| FRCC | |
| MRO | |
| NPCC | |
| RFC | |
| SERC | |
| SPP | |
| WECC | |

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

January 17, 2006

TO: REGISTERED BALLOT BODY
REGISTERED BALLOT BODY REGISTERED USERS
STANDARDS LISTSERVER
NERC ROSTER

Ladies and Gentlemen:

**REVISED Announcement of NERC Standards Actions — January 17, 2006**

The Standard Authorization Committee has taken the following standards actions:

### Proposed Standards Posted for Pre-ballot Review

The proposed cyber security and coordinate interchange standards have been posted for a 30-day pre-ballot review through February 15, 2006. Balloting of this group of proposed standards is expected to begin February 17, 2006. Members of the registered ballot body who wish to vote on this group of proposed standards must join the ballot pool prior to the commencement of the balloting.

### Proposed Standards Posted for Comment

The proposed standards on balancing authority, reliability coordinator, and transmission operator certification have been posted for a 30-day comment period through February 15, 2006. Please use the comment form (balancing authority, reliability coordinator, transmission operator) to provide any comments on these proposed standards.

### SARs Posted for Comment

- A SAR on relay loadability has been posted for a 30-day comment period through February 15, 2006. This SAR addresses Recommendation 21a of the U.S.-Canada Power System Outage Task Force and NERC Blackout Recommendation 8a, regarding the interaction and operation of relays and protection systems during power system transients. Please use this comment form to provide any comments on this SAR.
- A SAR on fuel supply or delivery disruption reporting has been posted for a 30-day comment period through February 15, 2006. This SAR proposes to develop a standard to require the reporting of fuel supply or delivery disruptions that cause a change in the status of the availability of any unit. Please use this comment form to provide any comments on this SAR.

### Drafting Team Nominations

The Standard Authorization Committee is soliciting drafting team members to help the SAR requesters respond to stakeholder comments received on each of the three SARs listed above. If you are interested in volunteering for one or more of these SAR drafting teams, please submit the nomination form, available through the hotlinks for each SAR, by February 1, 2006.

**Standards Development Process**

The NERC posting and balloting procedures are described in the *Reliability Standards Process Manual*, which contains all the procedures governing the standards development process. NERC follows this process, which is approved by the American National Standards Institute, to develop its standards and strives to address all comments submitted during the development of a standard. Stakeholders who feel their comments are not satisfactorily addressed have the option to appeal. A detailed explanation of the appeals process appears on page 23 of the manual.

The value and usefulness of the NERC reliability standards depend on the input of industry experts and all reliability stakeholders. Thank you for participating in the development of NERC reliability standards.

Please send questions to Mark Ladrow at mark.ladrow@nerc.net, or call 609-452-8060.

Sincerely,

Mark Ladrow

Mark Ladrow
Manager – Standards

# Working Paper

# on a

# Proposed Transmission Relay Loadability Standard

North American Electric Reliability Council

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

Approved by the NERC Planning Committee
for Submittal to
NERC Standards Authorization Committee

December 7, 2005

# Introduction

This "Working Paper on a Proposed Transmission Relay Loadability Standard" was prepared by the NERC Planning Committee's System Protection and Control Task Force. It provides a proposed draft standard on transmission relay loadability using the NERC Standards Development Process format for NERC reliability standards.

The purpose of the proposed standard is to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages. This transmission relay loadability recommendation is based on NERC Blackout Recommendation 8a, Improve System Protection to Slow or Limit the Spread of Future Cascading Outages, as included in the NERC Board of Trustees approved February 10, 2004 document, "August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts," and the U.S.-Canada Power System Outage Task Force Recommendation 21A, Make More Effective and Wider Use of System Protection Measures, as included in the task force's April 2004 report, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations."

The proposed transmission relay loadability standard attempts to codify the requirements and criteria used to implement the above NERC and U.S.-Canada Power System Outage Task Force relay recommendations.

The purpose of this working paper is to provide assistance to the NERC Standards Authorization Committee in its consideration of the proposed standard authorization request on transmission relay loadability approved by the NERC Planning Committee at its December 7, 2005 meeting. It may also be useful to any SAC-assigned SAR or standard drafting team.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. Briefly list the major steps completed, such as appointment of a drafting team, each draft of the SAR or standard that was posted, consideration of comments posted, field testing, ballots, etc.
2.

**Description of Current Draft:**

This is the initial draft of the Transmission Relay Loadability Standard. It codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.*

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Present this draft to the Planning Committee for approval for submission to the Standards Authorization Committee as part of a Standards Authorization Request. | December, 2005 |
| 2. | |
| | |
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## Definitions of Terms

**Emergency Ampere Rating:** "The highest seasonal ampere circuit rating (that most closely approximates a 4-hour rating) that must be accommodated by relay settings to prevent incursion." That rating will typically be the winter short-term (four-hour) emergency rating of the line and series elements. The line rating should be determined by the lowest ampere rated device in the line (conductor, airswitch, breaker, wavetrap, series transformer, series capacitors, reactors, etc) or by the sag design limit of the transmission line for the selected conditions. The relay evaluation should use whatever ampere rating currently used that most closely approximates a 4-hour rating.

**Operationally Significant Circuits:** The Regional Reliability Organizations (RROs) are responsible for the determination of Operationally Significant Circuits, which include all of the following:

- All circuits that are elements of Flowgates in the Eastern Interconnection, Commercially Significant Constraints in the Texas Interconnection, or Rated Paths in the Western Interconnection. This includes both the monitored and outage element for Outage Transfer Distribution Factor (OTDF) sets.
- All circuits that are elements of system operating limits (SOLs) and interconnection reliability operating limits (IROLs), including both monitored and outage elements.
- All circuits that are directly related to off-site power supply to nuclear plants. Any circuit that adversely impacts voltages on the off-site power bus at a nuclear plant by its outage must be included, regardless of its proximity to the plant.
- Other circuits determined and agreed to by the reliability authority/coordinator and the RROs.

**Transmission Protection System Owners (TPSOs):** Entities that own and/or operate protective relaying systems applied to protect transmission facilities operated at 100 kV and above, including transformer banks with low-voltage terminals operated at 100 kV and above.

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-___-1

**3. Purpose:** To ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages.

**4. Applicability**

**4.1.** This standard pertains to phase protection systems applied to:

**4.1.1** Transmission lines operated at 200 kV and above

**4.1.2** Transmission lines operated at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above voltage levels

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.

**4.2.** Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:

**4.2.1** Phase distance

**4.2.2** Out-of-step tripping

**4.2.3** Out-of-step blocking

**4.2.4** Switch-on-to-fault

**4.2.5** Overcurrent relays

**4.2.6** Communications aided protection schemes including but not limited to:

**4.2.6.1** Permissive overreach transfer trip (POTT)

**4.2.6.2** Permissive under-reach transfer trip (PUTT)

**4.2.6.3** Directional comparison blocking (DCB)

**4.3.** The following protection systems are <u>excluded</u> from requirements of this standard:

**4.3.1** Relay elements that are only enabled when other relays or associated systems fail.

**4.3.1.1** Overcurrent elements that are only enabled during loss of potential conditions.

**4.3.1.2** Elements that are only enabled during a loss of communications.

**4.3.2** Protection systems intended for the detection of ground fault conditions.

**4.3.3** Protection systems intended for protection during stable power swings.

**4.3.4** Generator protection relays that are susceptible to load.

**4.3.5** Relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**4.4.** This standard applies to the following entities:

**4.4.1** Regional Reliability Organizations.

**4.4.2** Transmission Owners that are Transmission Protection System Owners (TPSOs).

**4.4.3** Generation Owners that are TPSOs.

**4.4.4** Distribution Providers that are TPSOs.

**5. (Proposed) Effective Dates:**

**5.1.** For circuits described in 4.1.1and 4.1.3 above — January 1, 2008

**5.2.** For circuits described in 4.1.2 and 4.1.4 above — July 1, 2008

## B. Requirements

**R1.** Protection system applications and settings shall not limit transmission use. All transmission relays shall be set to ensure that transmission facilities are not unnecessarily interrupted during system disturbances when operator action within the first 15 minutes could alleviate potentially damaging overloads or prevent cascading outages.

**R1.1.** The desired emergency loadability of a transmission line may be limited by the conductor thermal capability, maximum power transfer, or series capacitor emergency rating. Any one of the following may be used to determine the required phase protective relay loadability:

General loadability statement

**R1.1.1.** Transmission line relays shall not operate at or below 150% of the Emergency Ampere Rating of a circuit ($I_{emergency}$), assuming a 0.85 per unit voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{emergency}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{emergency}$ = Emergency Ampere Rating

**R1.1.1.1.** This calculation must be redone whenever $I_{emergency}$ changes.

Exception 1 parallel

**R1.1.2.** **Utilize the 15-Minute Rating of the Transmission Line** — The tripping relay should not operate at or below 1.15 times an established 15-minute Emergency Ampere Rating ($I_{emergency}$) of the line.

When evaluating a distance relay, assume a 0.85 per unit relay voltage and power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{emergency}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{emergency}$ = Emergency Ampere Rating

**R1.1.2.1.** This calculation must be redone whenever $I_{emergency}$ changes.

**R1.1.2.2.** Transmission operators shall be instructed to take immediate remedial steps, including dropping load, if the current on the circuit reaches $I_{emergency}$.

Exception
2 parallel

**R1.1.3. Maximum Power Transfer Limit Across a Transmission Line —** Transmission line tripping relays shall not operate at or below the maximum power transfer capability of the line.

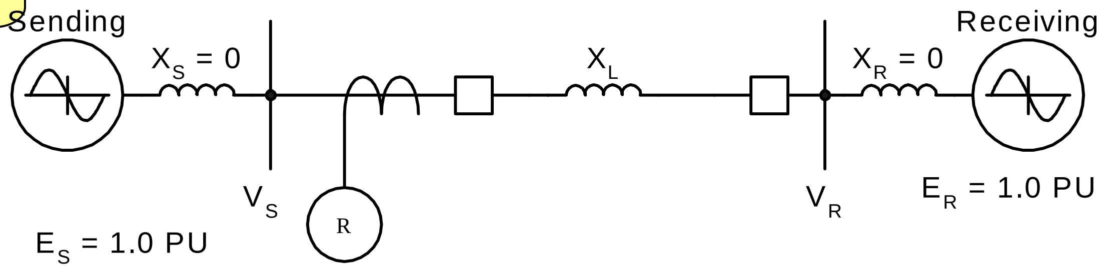


**Figure 1 — Maximum Power Transfer**

Where:

$P$ = Power flow across the transmission line

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$\delta$ = Voltage angle between $V_S$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$X_L$ = Reactance of the transmission line in ohms

$I_{max}$ = Maximum power transfer capability in Amperes:

$$I_{\max} = \frac{0.816 \times V_{L-L}}{X_L}$$

**R1.1.3.1.** This calculation shall be redone whenever the impedance of the circuit changes.

**R1.1.4. Maximum Power Transfer Limit Across a Transmission Line Based on the Breaker Interrupting Ratings at Each End of the Line —** Transmission line relays shall not operate at or below the maximum power transfer capability of the circuit including the breaker ratings.

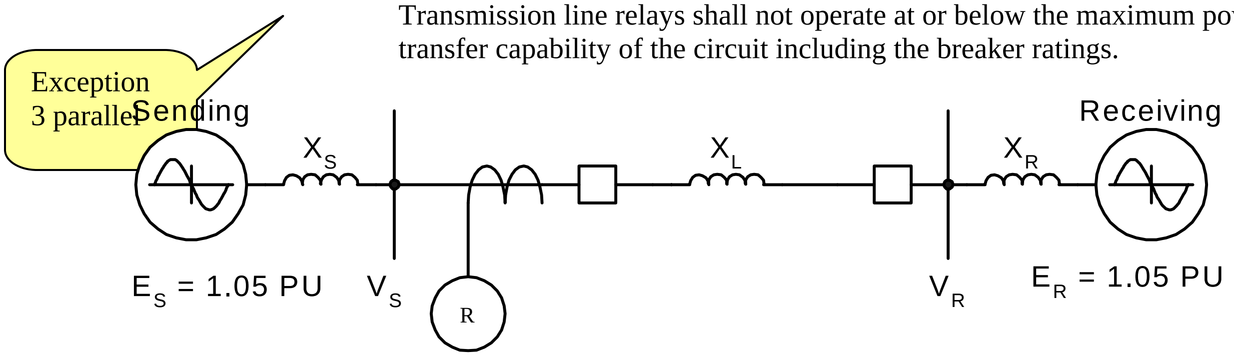


**Figure 2 — Maximum Power Transfer Based on Breaker Interrupting Ratings**

Where:

$P$ = Power flow across the transmission line

$$P = \frac{(E_S \times E_R \times \sin\delta)}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Calculated reactance in ohms of the sending bus (based on breaker interrupting duty)

$X_R$ = Calculated reactance in ohms of the receiving bus (based on breaker interrupting duty)

$X_L$ = Reactance of the transmission line in ohms

The tripping relay should not operate at or below a calculated $I_{max}$:

$$I_{\max} = \frac{0.857 \times V_{L-L}}{\left[\frac{0.577 \times V_{L-L}}{I_{BRS}} + \frac{0.577 \times V_{L-L}}{I_{BRR}} + X_L\right]}$$

Where:

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ =Maximum power transfer capability of the circuit including the breaker ratings

$I_{BRS}$ = Interrupting rating of the breaker in amps on the sending bus

$I_{BRR}$ = Interrupting rating of the breaker in amps on the receiving bus

$X_L$ = Reactance of the transmission line in ohms

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum power transfer capability of the circuit including the breaker ratings

**R1.1.4.1.** This calculation shall be redone whenever the breakers are overdutied or replaced.

**R1.2.** The desired emergency loadability of a transmission line may be "limited" by source, generation capability, or system configuration. In such cases, any one of the following requirements may be used instead of R1 to determine the phase protective relay settings.

**R1.2.1. System's Site-Specific Calculated Maximum Power Transfer Limit** — Transmission line relays shall not operate at or below the maximum power transfer capability of the line including the line source impedances.

Exception
4 parallel

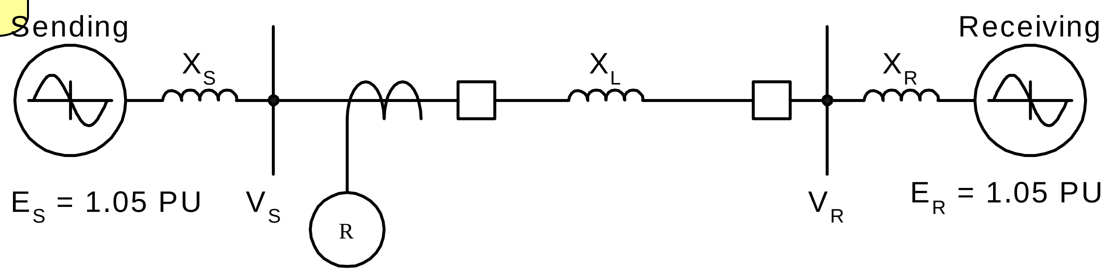


**Figure 3 — Maximum Power Transfer Based on Breaker Interrupting Ratings**

The tripping relay should not operate at or below a calculated $I_{max}$:

$$I_{\max} = \frac{0.606 \times V_{L-L}}{\left(X_S + X_R + X_L\right)}$$

Where:

$I_{max}$ = Maximum power transfer capability of the circuit including the line source impedances

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum power transfer capability of the circuit including the line source impedances

**R1.2.1.1.** This calculation shall be re-verified annually or whenever major system changes are made.

**R1.2.2.** **Weak Source Systems** — Transmission line relays applied at weak source terminals shall not operate at or below 1.15 times the maximum end-of-line three-phase fault current magnitude.

Exception 6 parallel

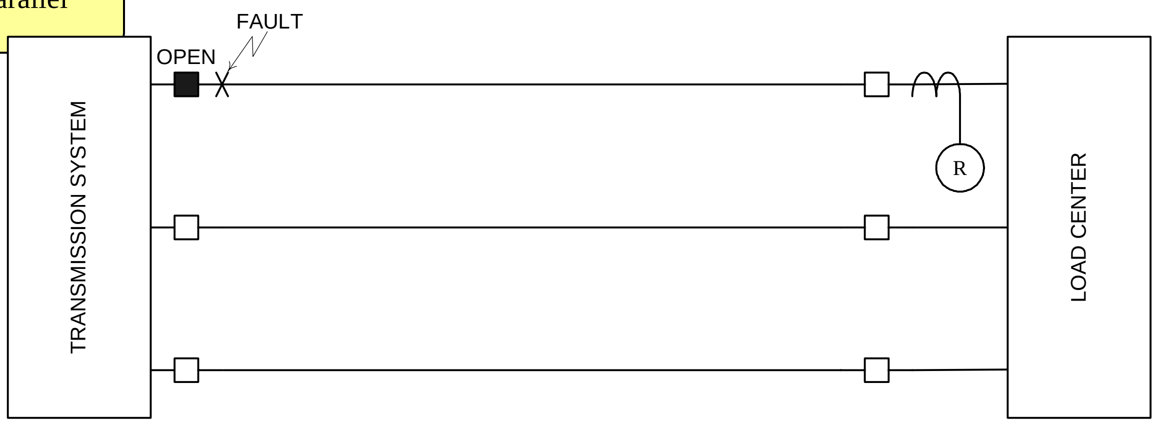


**Figure 3 — Weak Source Systems**

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer.

$$I_{\max} = \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{\max} = 1.485 \times I_{fault}$$

Where:

$I_{max}$ = Maximum power transfer capability of the circuit.

$I_{fault}$ = The line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum power transfer capability of the circuit.

**R1.2.2.1.** This calculation shall be redone whenever the maximum end-of-line three-phase fault current changes significantly.

Exception 7 parallel

**R1.2.3. Long Line Relay Loadability** — The desired emergency loadability of a transmission line may be "limited" by the requirement to adequately protect the transmission line. In such cases, the following may be used instead of R1 to determine the phase protective relay settings. Transmission line distance relays applied to two-terminal line set no longer than 125% of the line impedance.

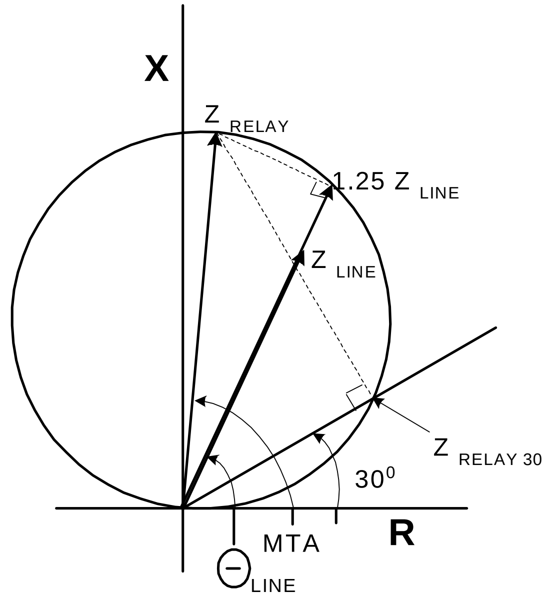


**Figure 4 — Long Line relay Loadability**

**R1.2.3.1.** The maximum torque angle (MTA) shall be set as close to 90 degrees as possible.

**R1.2.3.2.** The short-term emergency rating ($I_{emergency}$) of the line shall be equal to or less than:

$$I_{emergency} = \left(\frac{0.341 \times V_{L-L}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)$$

Where:

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree power factor angle before reaching the relay trip point

$V_{L-L}$ = Rated line-to-line voltage

$Z_{line}$ = Impedance of the line in ohms.

$MTA$ = Maximum torque angle, the angle of maximum relay *reach*

$Z_{relay}$ = Relay setting at the maximum torque angle

$\Theta_{line}$ = Line impedance angle

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{emergency}}$$

Where:

$Z_{relay30}$ = Relay reach (trip point) in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree power factor angle before reaching the relay trip point

**R1.2.3.3.** No planning contingency shall identify any conditions where a recoverable flow is greater than $I_{emergency}$.

**R1.2.3.4.** $I_{emergency}$ of the circuit shall be used in all planning and operational modeling for the short-term (15-minute or that most closely approximates a 15-minute) emergency rating.

**R1.2.3.5.** Transmission Operators shall be instructed to take immediate remedial steps, including dropping load, if the current reaches $I_{emergency}$.

Exception 8 parallel

**R1.2.4. Three (or more) Terminal Lines and Lines with One or More Radial Taps** — The desired emergency loadability of a transmission line may be "limited" by the requirement to adequately protect the transmission line. In such cases, the following may be used instead of R1 to determine the phase protective relay settings. Transmission line distance relays applied to multi-terminal line set no longer than 125% of the apparent impedance.

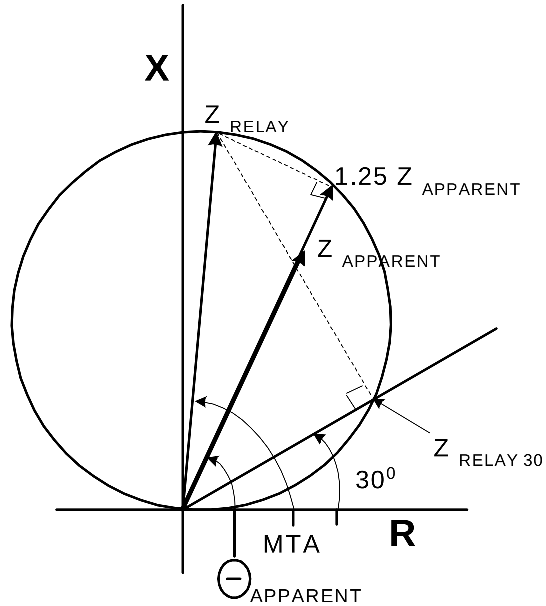


**Figure 5 — Three (or more) Terminal Lines and Lines with One or More Radial Taps**

**R1.2.4.1.** The maximum torque angle (MTA) shall be set as close to 90 degrees as possible.

**R1.2.4.2.** The short-term emergency rating ($I_{emergency}$) of the line shall be equal to or less than:

$$I_{emergency} = \left( \frac{0.341 \times V_{L-L}}{Z_{apparent}} \right) \times \left( \frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)} \right)$$

Where:

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree power factor angle before reaching the trip point

$V_{L-L}$ = Rated line-to-line voltage

$Z_{apparent}$ = Apparent line impedance in ohms as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed where applicable) by the TPSO for a fault at the most electrically distant line terminal for system conditions normally used in their protective relaying setting practices.

*MTA* = Maximum torque angle, the angle of maximum relay reach

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{emergency}}$$

Where:

$Z_{relay30}$ = Relay reach (trip point) in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree power factor angle before reaching the trip point

**R1.2.4.3.** No planning contingency shall identify any conditions where a recoverable flow is greater than $I_{emergency}$.

**R1.2.4.4.** $I_{emergency}$ of the circuit shall be used in all planning and operational modeling for the short-term (15-minute or that most closely approximates a 15-minute) emergency rating.

**R1.2.4.5.** Transmission Operators shall be instructed to take immediate remedial steps, including dropping load, if the current reaches $I_{emergency}$.

**R1.2.5. Generation Remote to Load** — Transmission line relays applied on transmission lines connected to generation stations remote to load shall not operate at or below 1.15 times twice the generation capability.

Exception
9 parallel

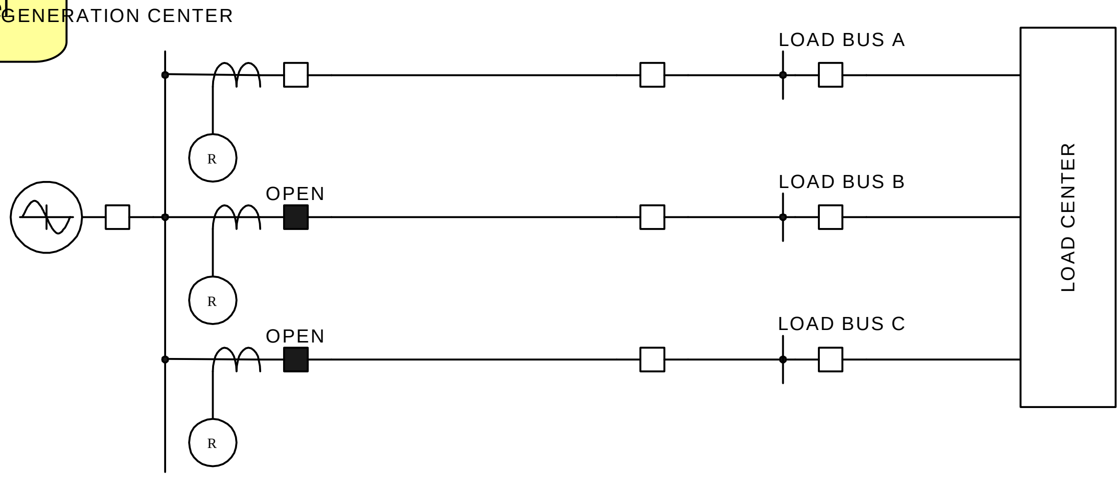


**Figure 6 — Generation Connected to System – Multiple Lines**

**R1.2.5.1.** The TSPO shall determine the maximum current flow from the generation center to the load center under any system condition. In the case of multiple lines, this includes situations where all the other lines that connect the generator to the system are out of service.

**R1.2.5.2.** The reliability coordinator / reliability authority must concur with this maximum flow.

**R1.2.5.3.** This calculation shall be reviewed whenever the generation sources change.

**R1.2.5.4.** The total generation output is defined as two times[1] the aggregate of the nameplate ratings of the generators in MVA converted to amps at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

$$I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{L-L}}$$

Where:

$MVA_{max}$ = Twice the aggregate of the nameplate ratings of the generators in MVA.

[1] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$N$ = Number of generators connected to the generation bus

$MW_{nameplate}$ = Nameplate ratings of the generators in MW

$PF_{nameplate}$ = Nameplate power factor ratings of the generators

$I_{genmax}$ = Current in Amperes associated with the aggregate of the nameplate ratings of the generators in MVA at the relay location at 100% voltage.

$V_{L-L}$ = Rated line-to-line voltage

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{gen\max}}$$

Where:

$Z_{relay30}$ = Relay trip point at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{genmax}$ = Current in Amperes associated with the aggregate of the nameplate ratings of the generators in MVA at the relay location at 100% voltage.

Exception 10 parallel

**R1.2.6. Load Remote to Generation** — Transmission line relays applied on transmission lines connected at the load end, remote to generation station shall not operate at or below 1.15 times the maximum current flow from the load to the generation source under any system configuration.

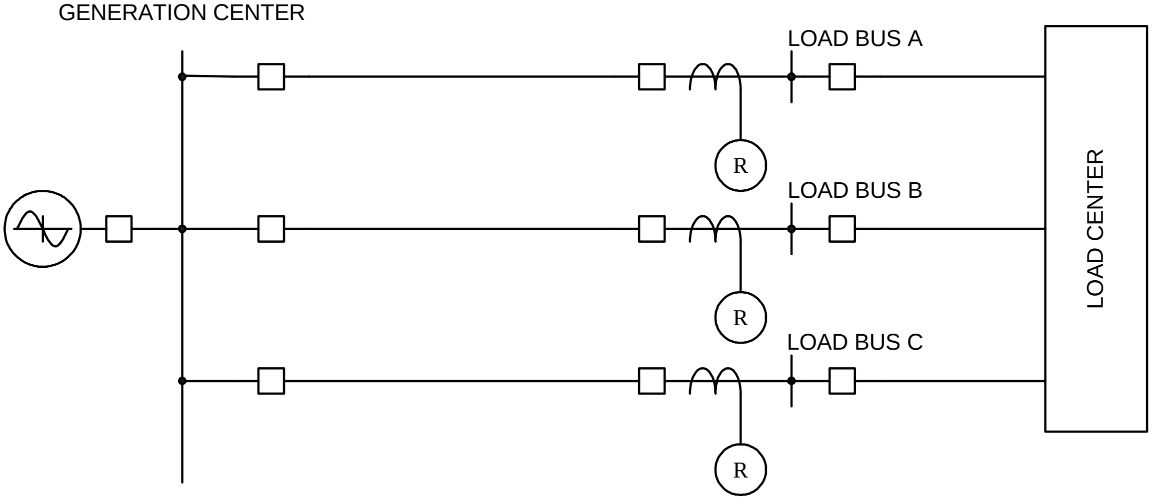


**Figure 7 — Load Remote to Generation**

The TSPO shall determine the maximum current flow from the load center to the generation center under any system condition. In the case of multiple lines, this includes situations where all the other lines that connect the generator to the system are out of service.

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum current flow in Amperes determined by the TPSO

**R1.2.6.1.** The reliability coordinator must concur with this maximum flow.

**R1.2.7. Transmission to Remote Cohesive Load Center** — Transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system shall not operate at or below 1.15 times the maximum current flow from the system to the load under any system configuration.

Exception 11 parallel

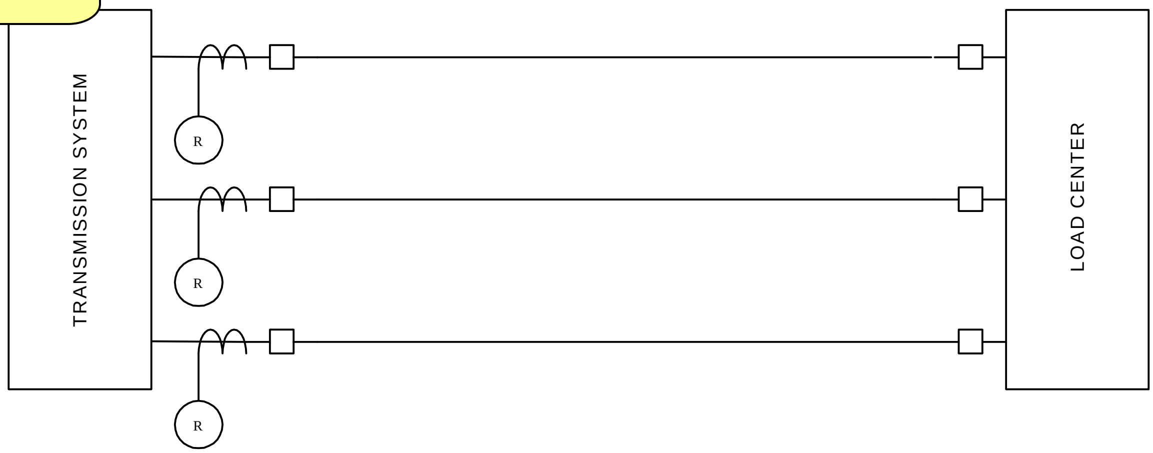


**Figure 8 — Transmission to Remote Cohesive Load Center**

The TSPO shall determine the maximum current flow from the bulk system to the load center under any system condition. In the case of multiple lines, this includes situations where all the other lines that connect the generator to the system are out of service.

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum current flow in Amperes determined by the TPSO

**R1.2.7.1.** The reliability coordinator must concur with this maximum flow.

Exception
12 parallel

**R1.2.8. Cohesive Load Center Remote to Transmission System** — Transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system shall not operate at or below 1.15 times the maximum current flow from the load to the system under any system configuration.

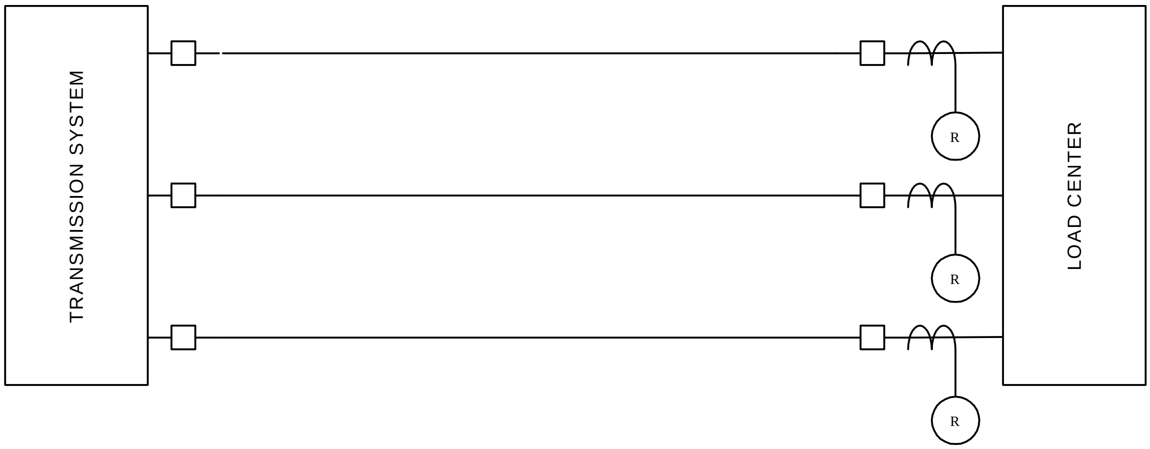


**Figure 9 — Cohesive Load Center Remote to Transmission System**

**Additional requirements:**

The TSPO shall determine the maximum current flow from the load center to the bulk system under any system condition. In the case of multiple lines, this includes situations where all the other lines that connect the generator to the system are out of service.

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum current flow in Amperes determined by the TPSO

**R1.2.8.1.** The reliability coordinator must concur with this maximum flow.

Exception 14 parallel

**R1.2.9. Transformer Overcurrent Protection** — Transformers have short term loadability capability. Relays applied to protect transformers must provide emergency loadability. One of the following shall be used to determine the phase protective relay loadability:

**R1.2.9.1.** If the TPSO uses transformer fault protection relays, they shall be reviewed to verify that the relay is not set to operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating[2]
- 115% of the highest operator established emergency transformer rating

**R1.2.9.2.** If the TPSO uses relays for overload protection for excessive load conditions (in addition to planned system operator action) that operates below the level stated above, one of the following conditions must apply:

- The relays are set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- The relays are supervised by either a top oil or simulated winding hot spot element. The setting should be no less than 100° C for the top oil or 140° C[3] for the winding hot spot.

2 Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally be sustained for several minutes without damage or appreciable loss of life to the transformer. See ANSI/IEEE Standard C57.92, Table 3.

3 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

**R1.2.10. TPSO-Established Maximum Loading Capability** – Other system situations may exist which present practical limitations on the load which a circuit may carry. In such cases, the TPSO may utilize such limitations when determining the required relay loadability.

Special Exception parallel

**R1.2.10.1.** The TPSO shall submit documentation for RRO review such that the Region can verify the limitation and approve its use.

**R1.2.10.2.** The reliability coordinator must concur with this maximum flow.

**R1.2.10.3.** No planning contingency shall identify any conditions where a recoverable flow is greater than this maximum flow.

**R1.2.10.4.** The maximum flow of the circuit shall be used in all planning and operational modeling for the short-term (15-minute or that most closely approximates a 15-minute) emergency rating.

**R1.2.10.5.** Transmission Operators shall be instructed to take immediate remedial steps, including dropping load, if the current reaches this maximum flow.

### R1.3. Series Capacitor and Pilot Relaying

Exception
5 parallel

**R1.3.1. Special Considerations for Series-Compensated Lines** — For series compensated lines, transmission line relays shall not operate at or below the maximum power transfer capability of the line ($I_{max}$), determined as the greater of:

- 115% of the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.
- $I_{max}$ (where $I_{max}$ is calculated under R1.1.3, R1.1.4, or R1.2.1, using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

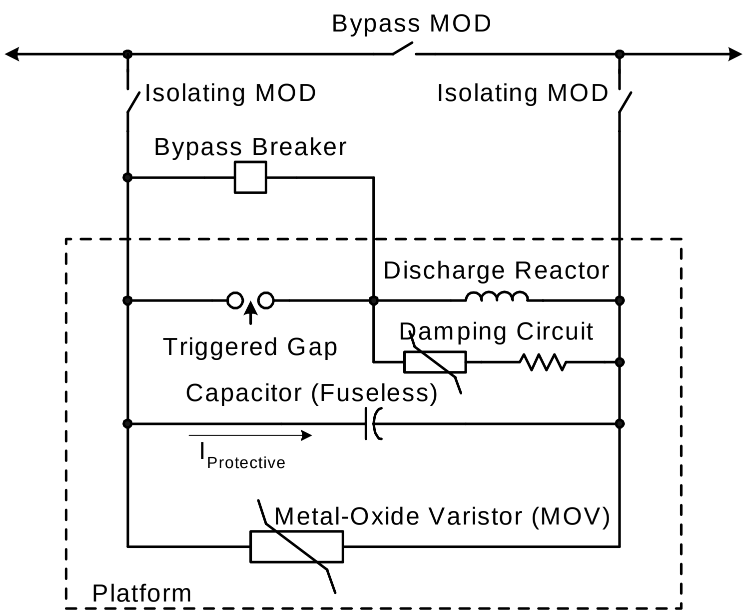


**Figure 10 — Series Capacitor Components**

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a power factor angle of 30 degrees.

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{max}$ = Maximum power transfer capability in Amperes

**R1.3.1.1.** If $I_{max}$ is based on the breaker ratings, this calculation shall be redone whenever the breakers are overdutied or replaced.

**R1.3.1.2.** If $I_{max}$ is based on the line source impedances, this calculation shall be re-verified annually or whenever major system changes are made.

Exception 13 parallel

**R1.3.2.** **Impedance-Based Pilot Relaying Schemes** — Transmission line relays applied in communications aided tripping schemes shall meet the requirements of R1.1.1 through R1.2.4 unless all of the following requirements are met:

**R1.3.2.1.** The overreaching impedance elements are used only as part of the pilot scheme.

**R1.3.2.2.** The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.

**R1.3.2.3.** The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. This generally does not apply to directional comparison blocking schemes.

**R1.3.2.4.** The TPSO shall furnish calculations which establish that the loadability of the scheme as a whole meets the NERC loadability requirement for the protected line.

**R2.** **Determination of Operationally Significant Circuits** — The Regional Reliability Organization shall determine Operationally Significant Circuits between 100 kV and 200 kV for the purposes of evaluating protection system loadability for their region.

**R2.1.** The Regional Reliability Organization shall develop and maintain a methodology for determining Operationally Significant Circuits

**R2.2.** Documentation of the RRO methodology for determining Operationally Significant Circuits shall be provided to NERC annually and upon request within 30 days.

**R2.3.** The RRO shall annually identify Operationally Significant Circuits between 100 kV and 200 kV.

**R3.** **TPSO Reporting Requirements** — TPSOs shall provide applicable documentation of Transmission Relay Loadability to the RROs annually and upon request within 30 days:

**R3.1.** Provide self-certification of relays that comply with R1.1.

**R3.2.** Documentation of relays conformance with R1.2.

**R3.3.** Documentation of relays conformance with R1.1 or R1.2 for relays systems identified in R1.3.

Documentation of procedures used for determining and maintaining compliance, and records relating to relay loadability of all applicable circuits shall be subject to audit by the RRO or NERC.

**R4.** **RRO Reporting Requirements —** RROs shall review the compliance of TPSOs with R1 and R3. RROs provide a summary report with all applicable documentation to NERC annually and upon request within 30 days.

## C. Measures

**M1.** TPSO's relay applications and settings are in compliance with transmission loadability criteria in R1.

**M2.** Documentation of the methodology for RRO determination of Operationally Significant Circuits is in compliance with R2.

**M3.** TPSOs provide applicable documentation of Transmission Relay Loadability to the RROs

**M3.1** Self-certification of relays that comply with R1.1.

**M3.2** Documentation of relays compliance with R1.2.

**M3.3** Documentation of relays compliance with R1.1 or R1.2 for relays systems identified in R1.3.

**M4.** RROs summary report complies with R4.

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

**1.1.1** For PRC-XXX-1 R1, the RRO

**1.1.2** For PRC-XXX-1 R2, the NERC

**1.1.3** For PRC-XXX-1 R3, the RRO

**1.1.4** For PRC-XXX-1 R4, the NERC

**1.2. Compliance Monitoring Period and Reset Timeframe**

One calendar year

**1.3. Data Retention**

The TPSO shall retain current documentation and any changes to it for three years.

The Regional Reliability Organization shall retain current documentation and any changes to it for three years.

The Compliance Monitor will retain its audit data for three years.

**1.4. Additional Compliance Information**

Not applicable

**2. Levels of Non-Compliance**

**2.1. Level 1:**

**2.1.1** M1 — Through RRO review, TPSO's relay applications and settings are found to be not in compliance with transmission loadability criteria in R1 due to a calculation error.

**2.1.2** M2 — Complete RRO documentation of Operationally Significant Circuits not provided according to schedule.

**2.1.3** M3 — TPSO documentation of Transmission Relay Loadability not provided according to schedule.

**2.1.4** M4 — RRO documentation submittal to NERC not provided according to schedule.

**2.2. Level 2:**

**2.2.1** M1 — If during a disturbance analysis, TPSO's relay applications and settings are found to be not in compliance with transmission loadability criteria in R1 due to a calculation error, but does not cause or contribute to the disturbance.

**2.2.2** M2 —RRO documentation of Operationally Significant Circuits provided, but incomplete.

**2.2.3** M3 — TPSO documentation of Transmission Relay Loadability provided, but incomplete.

**2.2.4** M4 — RRO documentation submittal to NERC provided, but incomplete.

**2.3. Level 3:**

**2.3.1** M1 — TPSO's relay applications and settings are not in compliance with transmission loadability criteria in R1.

**2.3.2** M2 — RRO documentation of Operationally Significant Circuits not provided.

**2.3.3** M3 — TPSO documentation of Transmission Relay Loadability not provided.

**2.3.4** M4 — RRO documentation submittal to NERC not provided.

**2.4. Level 4:**

**2.4.1** M1 — TPSO's relay applications and settings are not in compliance with transmission loadability criteria in R1, and cause or is contributory to a reportable disturbance as defined in Standard EOP-004-1 — Disturbance Reporting.

**2.4.2** M2 — Not applicable

**2.4.3** M3 — Not applicable

**2.4.4** M4 — Not applicable

## E. Regional Differences

**1.** None

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|

# Relay Loadability SAR Drafting Team Nomination Form

Please return this form to sarcomm@nerc.com by February 3, 2006. For questions, please contact Mark Ladrow at 609-452-8060 or mark.ladrow@nerc.net.

Please note this drafting team will likely meet initially in late February or early March 2006 to review and respond to comments on the SAR posted, concurrently with this posting, on the NERC Web site. Subsequently, the team will determine and make recommendations for the next actions necessary for standard development. The complete meeting schedule has not been determined yet. It is expected the teams will meet several times in 2006, including face-to-face meetings, as well as meetings facilitated through various remote meeting technologies. **All candidates should be prepared to participate actively at these meetings.**

| | | |
|---|---|---|
| Name:<br><br>Organization:<br><br>Address:<br><br><br><br>Office Telephone:<br><br>E-mail: | | |
| **Please briefly describe your experience and qualifications to serve on the Relay Loadability SAR Drafting Team. Candidates should have expertise in one or more of the following areas: transmission planning, relay engineering, transmission design, or generation operations. Previous experience working on or applying NERC standards is beneficial, but not a requirement.** | | |
| **I represent the following NERC Reliability Region(s) (check all that apply):** | **I represent the following Industry Segment (check one):** | |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |

| | | |
|---|---|---|
| ☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, and Provincial Regulatory or other Government Entities |

**Which of the following Function(s)[1] do you have expertise or responsibilities:**

| | |
|---|---|
| ☐ Reliability Authority | ☐ Transmission Service Provider |
| ☐ Balancing Authority | ☐ Transmission Owner |
| ☐ Interchange Authority | ☐ Load Serving Entity |
| ☐ Planning Authority | ☐ Distribution Provider |
| ☐ Transmission Operator | ☐ Purchasing-selling Entity |
| ☐ Generator Operator | ☐ Generator Owner |
| ☐ Transmission Planner | ☐ Resource Planner |
| | ☐ Market Operator |

**Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.**

| | |
|---|---|
| Name: | Office Telephone: |
| Organization: | E-mail: |
| Name: | Office Telephone: |
| Organization: | E-mail: |

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

This form is to be used to submit comments on the proposed Relay Loadability SAR Standards. Comments must be submitted by **February 15, 2006**. You may submit the completed form by e-mailing it to: sarcomm@nerc.com with the words "Relay Loadability SAR Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

**ALL DATA ON THIS FORM WILL BE TRANSFERRED AUTOMATICALLY TO A DATABASE. IT IS THEREFORE IMPORTANT TO ADHERE TO THE FOLLOWING REQUIREMENTS:**

**DO:** **Do** enter text only, with no formatting or styles added.
**Do** use punctuation and capitalization as needed (except quotations).
**Do** use more than one form if responses do not fit in the spaces provided.
**Do** submit any formatted text or markups in a separate WORD file.

**DO NOT:** **Do not** insert tabs or paragraph returns in any data field.
**Do not** use numbering or bullets in any data field.
**Do not** use quotation marks in any data field.
**Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Charles W. Rogers | |
| Organization: | Consumers Energy Company | |
| Telephone: | 517-788-0027 | |
| E-mail: | cwrogers@cmsenergy.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☒ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

| **Group Comments (Complete this page if comments are from a group.)**<br>**Group Name:**<br>**Lead Contact:**<br>**Contact Organization:**<br>**Contact Segment:**<br>**Contact Telephone:**<br>**Contact E-mail:** | | | |
|---|---|---|---|
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on the prior page.

Background Information:

Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. During the 2003 blackout, relay loadability was found to have played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by “zone 3” relays, it was later found that other phase-distance and overcurrent relays also contributed to the cascade.

The purpose of the proposed Standard Authorization Request (SAR) is to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages. This transmission relay loadability SAR is submitted in response to the NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, as included in the document approved by the NERC Board of Trustees on February 10, 2004.

The available working paper includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. This working paper was prepared to assist the SAR and/or standards drafting team in the development of the proposed standard.

The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject “Relay Loadability SAR Comments” by February 15, 2006 to sarcomm@nerc.com

**1. Do you agree there is a reliability need for a standard addressing relay loadability?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: As noted in the SAR, this is an area which has contributed significantly to all major blackouts in North America. Additionally, actions directed by the NERC Planning Committee have resulted in much work on the part of the industry to resolve the problems. It's imperative that the work that has been accomplished is codified and captured within Reliability Standards.

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: The draft SAR seems well prepared, and seems to accurately capture the scope of the work done thus far within the industry.

### 3. Do you agree with the proposed applicability of the SAR?

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: All listed entities have a role in addressing the problems. It's only unfortunate that there isn't an entity within the Functional Model which is specifically and completely responsible for all facets of protective systems.

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments: This is wholly a technical issue related to the reliability of the electrical system. There is, of course, a cost issue related to continued compliance, but this isn't a commercial issue.

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☒ Yes

☐ No

Comments: Only to the extent that generator FAULT PROTECTIVE relays provide some degree of remote backup protection for transmission-voltage-level faults, and respond in such a way as to limit loading on the generator, generator step up transformer, or connection of the generator step up transformer to the transmission system. The applicability is well described in clause R1.2.5 of the posted Working Paper, and well limited by clause 4.3 of the Working Paper. This area of generator protection probably ultimately needs to be comprehensively addressed, but to do so would be premature based on the knowledge base within NERC and within the industry. Many other factors will probably also need to be considered to move forward to an increased degree on consideration of generator protection

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments: The clauses within the Working Paper seem to represent the major system issues endemic on all North American systems.

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: It's a superbly prepared SAR, and should go forward as is. Additionally, the Working Paper seems to represent an excellent first draft for the standard, and the process would probably be best served if the Standard Drafting Team, upon formation, would post the Working Paper as Draft 1 of the standard.

This form is to be used to submit comments on the proposed Relay Loadability SAR Standards. Comments must be submitted by **February 15, 2006**. You may submit the completed form by e-mailing it to: sarcomm@nerc.com with the words "Relay Loadability SAR Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

| | |
|---|---|
| **Group Name:** | Pepco Holdings, Inc. - Affiliates |
| **Lead Contact:** | **Richard Kafka** |
| **Contact Organization:** | **Potomac Electric Power Co** |
| **Contact Segment:** | **1** |
| **Contact Telephone:** | **301-469-5274** |
| **Contact E-mail:** | **rjkafka@pepcoholdings.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Evan Sage | Potomac Electric Power Co | RFC | 1 |
| Alvin Depew | Potomac Electric Power Co | RFC | 1 |
| Carl Kinsley | Delmarva Power and Light | RFC | 1 |
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**1. Do you agree there is a reliability need for a standard addressing relay loadability?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: The SAR properly excludes generation protection systems. We acknowledge that the SAR should (and does) include transmission protection systems located (and possibly owned) by the Generation Owner

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

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| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ FRCC<br>☐ MRO<br>☒ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable | ☐ | 1 — Transmission Owners |
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| **Group Comments (Complete this page if comments are from a group.)** | |
|---|---|
| **Group Name:** | CP9, Reliability Standards Working Group |
| **Lead Contact:** | Guy Zito |
| **Contact Organization:** | Northeast Power Coordinating Council (NPCC) |
| **Contact Segment:** | 2 |
| **Contact Telephone:** | 212-840-1070 |
| **Contact E-mail:** | gzito@npcc.org |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Kathleen Goodman | ISO-New England | NPCC | 2 |
| Michael Shiavone | National Grid | NPCC | 1 |
| Roger Champagne | TransEnergie (Quebec) | NPCC | 1 |
| David Kiguel | Hydro One Network | NPCC | 1 |
| Ron Falsetti | IESO (Ontario) | NPCC | 2 |
| Edwin Thompson | ConEdison | NPCC | 1 |
| Donald Nelson | MA Dept of Energy and Tele. | NPCC | |
| Sashi Parekh | MA Dept of Energy and Tele. | NPCC | |
| George Dunn | New York Power Authority | NPCC | 1 |
| Brian Hogue | Northeast Power Coor. Council | NPCC | 2 |
| Alan Adamson | New York State Rel. Council | NPCC | 2 |
| Guy Zito | Northeast Power Coor. Council | NPCC | 2 |
| Greg Campoli | New York ISO | NPCC | 2 |
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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: NPCC reserves the right as stated in the SAR that determining what circuits are classified as Operationally Significant Circuits is the Region's responsibility.  NPCC participating members are not in agreement with the definition as it appears in the "working paper".

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: While we agree with the applicable of the standard we also recognize that the equipment owners have concerns regarding the emergency loadibility of their equipment and the standard should recognize the ability for exceptions.

The TPSO definition in the whitepaper should be included in the SAR.

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: Although NPCC's participating members believe that for the purposes of this SAR the relays assocciated with generators should not be included in the scope, it is important that the issue of coordination between generator and transmission system protection be addressed elsewhere in the NERC standards.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments: The SAR and subsequent standard should emphasize that the loadibility should apply only during emergency situations and not as a matter of normal system operations.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Ed Davis | |
| Organization: | Entergy Services | |
| Telephone: | 601-339-2614 | |
| E-mail: | edavis@entergy.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

## 3. Do you agree with the proposed applicability of the SAR?

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:

The proposed criteria for determining Operationally Signficant Circuits should be more clear and concise. As written, misinterpretation is probable.

1. Does the term "Flowgates" refer to those facilities in the NERC Book of Flowgates? If so, please so state. If not, what is the definition of "Flowgates" as a proper term?

2. The phrase "All circuits that are elements of system operating limits" means what. Every transmission line has a rating that, when exceeded, constitutes a system operating limit. This seems to leave the door open to saying that every possible combination of outaged and monitor elements could be considered operationally signficant. It would be more practical to state that " All circuits that are elements of a reported SOL violation or IROL violation including both the monitored and outage elements"

3. With respect to the offsite power supply to nuclear plants, what is the criteria for "adverse impact"? If outage of a particular circuit drops the voltage at the offsite power bus for a nuclear plant from 1.02 per unit to 1.00 per unit, does this constitute an adverse impact? Hopefully not. Such would be impractical. A recommended alternative is "Any circuit, when outaged, that causes the voltage at the off-site power bus at a nuclear bus to exceed established operating limits".

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

   **If yes, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☐ No

Comments:

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments:

The draft standard will apply to transmission lines operated 200 kV and above. This assumes that all of these circuits are operationally significant and that may not be the case. The operationally significant criteria should be applied to all lines 100 kV and above.

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Kathleen Goodman |
| Organization: | ISO New England, Inc. |
| Telephone: | (413) 535-4111 |
| E-mail: | kgoodman@iso-ne.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

## 2. Do you agree with the proposed scope of the SAR?

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: ISO-NE believes that is it the Regions responsibility to determine what circuits are classified as "Operationally Significant Circuits."

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: This should be a future consideration for a staged implementation.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☒ Yes

☐ No

Comments: ISO-NE believes that because there are no uniform standards for rating facilities, such as conductors, transformers, etc. that have been accepted nationwide, it will be difficult to have all responsible entities comply with this Standard. The ISO believes that each Region must and should determine it's own standards for rating facilities, espeically if it pertains to determining which circuits are "operationally significant."

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: We feel that the definitions of TPSO and voltage classifications as noted on page SAR-6, should be included as part of the Standard. Furthermore, the Standard definitions should align with the working paper definitions.

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Alan Gale |
| Organization: | City of Tallahassee (TAL) |
| Telephone: | (850) 891-3025 |
| E-mail: | galea@talgov.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
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Background Information:

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The available working paper includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. This working paper was prepared to assist the SAR and/or standards drafting team in the development of the proposed standard.

The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject “Relay Loadability SAR Comments” by February 15, 2006 to sarcomm@nerc.com

1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☒ No

   Comments: See comments in 2 below.

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: The scope of the SAR as written is too much. The recommendations sited in the Blackout Reports recommended checking Zone 3 loadability only. The SAR also states that "It is imperative to the continued reliability of the North American power system that the problems of relay loadability remain corrected and that the technical solutions are properly codified in the NERC reliability standards." So from the SAR drafters own point of view, the problem has been fixed. We do not need to impose additional requirements and work on entities that are already doing their part in maintaining a reliable bulk electric system.

I agree that we should codify the requirements that we have already met for Zone 3 loadability, but question the cost vs. gain in pursuing this "monumental undertaking" for the lower voltage lines and transformers which will be an even greater undertaking than the previous one.

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

   **If yes, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments:

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

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|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

| **Group Comments (Complete this page if comments are from a group.)** | |
|---|---|
| **Group Name:** | Midwest Reliability Organization (MRO) |
| **Lead Contact:** | **Alan Boesch** |
| **Contact Organization:** | **MRO for group (Nebraska Public Power District for lead contact)** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **402-845-5210** |
| **Contact E-mail:** | **agboesc@nppd.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| **Terry Bilke** | **MISO** | **MRO** | **2** |
| **Robert Coish** | **MHEB** | **MRO** | **2** |
| **Dennis Florom** | **LES** | **MRO** | **2** |
| **Todd Gosnell** | **OPPD** | **MRO** | **2** |
| **Wayne Guttormson** | **SPC** | **MRO** | **2** |
| **Jim Maenner** | **WPS** | **MRO** | **2** |
| **Darrick Moe, Chair** | **WAPA** | **MRO** | **2** |
| **Tom Mielnik** | **MEC** | **MRO** | **2** |
| **Pam Oreschnick** | **XEL** | **MRO** | **2** |
| **Dick Pursley** | **GRE** | **MRO** | **2** |
| **Dave Rudolph** | **BEPC** | **MRO** | **2** |
| **Ken Goldsmith** | **ALT** | **MRO** | **2** |
| **Joe Knight, Secretary** | **MRO** | **MRO** | **2** |
| **27 Additional MRO Member** | **Companies not named above** | **MRO** | **2** |
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Background Information:

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The purpose of the proposed Standard Authorization Request (SAR) is to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages. This transmission relay loadability SAR is submitted in response to the NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, as included in the document approved by the NERC Board of Trustees on February 10, 2004.

The available working paper includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. This working paper was prepared to assist the SAR and/or standards drafting team in the development of the proposed standard.

The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject “Relay Loadability SAR Comments” by February 15, 2006 to sarcomm@nerc.com

1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The MRO believes that the Relay Loadability is a serious concern and the NERC System Protection and Control Task Force (SPCTF) is to be commended on developing a good GUIDELINE for determining relay loadability settings. Based on the information contained in the Working Paper on a Proposed Transmission Relay Loadability the MRO has reservations on the appropriateness of the working paper becoming a Reliability Standard. The MRO believes that this issue could be adequately addressed through additions to existing standards to consider relay loadability. The highly prescriptive nature of the working paper is not suitable for a Reliability Standard.

## 2. Do you agree with the proposed scope of the SAR?

### If not, please explain in the comment area.

☐ Yes

☒ No

Comments: The MRO is disappointed to see marked up version of the SAR posted on the NERC website. SARs should be in their final format prior to being posted.
The MRO questions whether the role of the NERC Reliability Standards is to codify technical solutions. We request that the NERC-SAC clarify this role. Codifying technical solutions seems inconsistent with the intent of standards process which is to focus on WHAT is required to maintain reliability not on how to do it (i.e., technical solutions).

The suggested draft Working Paper on a Proposed Transmission Relay Loadability Standard is a good GUIDELINE for determining relay loadability settings not a Reliability Standard. The draft requirements are overly prescriptive and focus on HOW to set relays not what is required to maintain reliability, i.e., that each Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator should optimize their system's ability to slow or stop an uncontrolled cascading failure of the power system. The MRO believes that this optimization is best addressed through existing standards such as the TPL standards. This provides for a complete and integrated response which Transmission System Protection Owner's (TPSO) can not provide.

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: Nothing in the SAR explains why this should apply to the RRO or Distribution Provider.

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

   **If yes, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: The working paper should not be turned into a Standard.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments: Without specific information about the content of the standard it is difficult to determine the necessity for Regional Differences.

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: Based on the draft standard that is included as a working paper the MRO would support a SAR of more limited scope if it focused on adding additional language to exisiting standards such as TPL-004 related to optimizing a system's ability to slow or stop an uncontrolled cascading failure of the power system.

This form is to be used to submit comments on the proposed Relay Loadability SAR Standards. Comments must be submitted by **February 15, 2006**. You may submit the completed form by e-mailing it to: sarcomm@nerc.com with the words “Relay Loadability SAR Comments” in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | William J. Smith |
| Organization: | Allegheny Power |
| Telephone: | (724) 838-6552 |
| E-mail: | |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
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**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments:

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Wayne Guttormson | |
| Organization: | SaskPower | |
| Telephone: | 306-566-2166 | |
| E-mail: | wguttormson@saskpower.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject “Relay Loadability SAR Comments” by February 15, 2006 to sarcomm@nerc.com

**1. Do you agree there is a reliability need for a standard addressing relay loadability?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: SaskPower believes that this issue is adequately addressed in following standards:
TPL-002-0 R1.3.10, TPL-003-0 R1.3.10, and TPL-004-0 R1.3.7; which require the Planning Authority and Transmission Plannner to include the effects of existing and planned protection systems in their transmission planning studies in order to evaluate system performance and mitigate any deficiencies.
FAC-008-1 and FAC-009-1; which require Transmission Owners (TO) and Generator Owners to have a Facility Ratings Methodology and to Establish and Communicate Facility Ratings. These standards address the most limiting applicable Equipment Rating, including relay protective devices, and applicable Emergency Ratings (if the TO allows emergency overloads).
PRC-001 which requires system protection coordination among operating entities.
The NERC System Protection and Control Task Force (SPCTF) is to be commended on developing a good GUIDELINE for determining relay loadability settings but SaskPower has serious reservations about its appropriateness for a Reliability Standard based on the information contained in the SAR and the Working Paper on a Proposed Transmission Relay Loadability Standard. The highly prescriptive nature of the working paper is not suitable for a Reliability Standard.

## 2. Do you agree with the proposed scope of the SAR?

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: SaskPower questions whether the role of the NERC Reliability Standards process is to codify technical solutions. WE REQUEST THAT THE NERC-SAC CLARIFY THIS ROLE. Codifying technical solutions seems inconsistent with the intent of standards process which is to focus on WHAT is required to maintain reliability not on HOW to do it (i.e., technical solutions). If NERC is to be codifying technical solutions WHY have we not been doing that with all of the other standards that have been developed to date.

SaskPower has the following additional comments for the Purpose/Industry Need section:

The purpose seems to overstate the role zone 3 played in the 2003 blackout in that relay loadability was not listed as a causal event in the final report. Quoting from the August 14, 2003, Blackout Final NERC Report, dated July 13, 2004, Section V, Conclusions and Recommendations, I. Conclusions and Recommendations, C. OTHER DEFICIENCIES, 1. Summary of Other Deficiencies Identified in the Blackout Investigation: Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system. The effects of zone 3 relays, the lack of under-voltage load shedding, and the coordination of underfrequency load shedding and generator protection are all areas requiring further investigation to determine if opportunities exist to limit or slow the spread of a cascading failure of the system.

The reference to ongoing contributor to system disturbances is too general and should be clarified. Is it referring to all types of contingencies (Category B, C & D) or just extreme contingencies (Category D)? Given the references to the 2003 Blackout we assume it is meant for Category D.

SaskPower has the following additional comments for the Detailed Description section:

Is the SAR intended to mitigate relay loadability impacts for all contingencies or just extreme contingencies? Is this not already covered by the TPL standards? TPL-002-0 R1.3.10, TPL-003-0 R1.3.10, and TPL-004-0 R1.3.7; require the Planning Authority and Transmission Plannner to include the effects of existing and planned protection systems in their transmission planning studies. If system performance deficiencies are found they are supposed to mitigate them.

The SAR still seems to imply that manual operator action is preferred over automatic action, due consideration must be given to both. Relying on operator action to mitigate extreme (Category D) contingencies may be somewhat problematic.

As well, SaskPower is concerned that this SAR will limit our ability to decide how we want our system to respond to extreme contingencies. As the Planning Authority and Reliability Coordinator for Saskatchewan this is our responsibility and we feel that it is best left up to us to decide on how the relays in our system and on our tie-lines are to be set based on our system performance requirements.

The suggested draft Working Paper on a Proposed Transmission Relay Loadability Standard is a good GUIDELINE for determining relay loadability settings not a Reliability Standard. The draft requirements are overly prescriptive and focus on HOW to set relays not WHAT is required to maintain reliability, i.e., that each Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator should optimize their system's ability to slow or stop an uncontrolled cascading failure of the power system. SaskPower believes that this optimization is adequately addressed through the TPL standards. This provides for a complete and integrated response which Transmission System Protection Owner's (TPSO) can not provide.

Some general comments on the draft standard:

R1.1.2 uses a 15 minute emergency rating. Will system operators be able to respond within 15 minutes for a Category B, C, or D contingency (R1.1.2.2)?

System topologies used in the examples are rather limiting, are they system equivalents or specific topologies?

Applying the required settings may be somewhat impractical. For example: The TPSO shall determine the maximum current flow … under ANY system condition. Suggest changing the language to any credible worst case system condition. In the case of multiple lines, this includes situations where ALL the other lines … are out of service. Is this a credible system condition? Does the TPSO have the capability to perform this analysis? Wouldn't this analysis be performed by the Planning Authority, Transmission Planner, Reliability Coordinator, or Transmission Operator?

R1.2.9. Transformer Overcurrent Protection: This requirement states that the TPSO must provide emergency loadability. SaskPower believes that Emergency Ratings for facilities are the sole responsibility of the TO (as per FAC-008 and 009) not the TPSO, and that emergency loadability is at the discretion of the TO. SaskPower also questions whether it is within the purview of this standard (or the SPCTF) to determine acceptable overloads or acceptable loss of life for ANY piece of equipment. Is this not the responsibility of the TO? As well, the protection philosophy used by the TO should be at the discretion of the TO as long as system performance criteria are met, and there has been proper coordination with the Planning Authority, Transmission Planner, Reliability Coordinator, and Transmission Operator.

R1.2.10.1 TPSO-Established Maximum Loading Capability: If the RRO is not approving Facility Ratings (FAC-008-1 and FAC-009-1) why is it approving this rating?

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: Nothing in the SAR explains why this should apply to the RRO. The RRO is referenced in the draft standard (which we are not supposed to comment on).

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: The working paper should not be turned into a Standard.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: SaskPower would vote NO on this draft standard if it were pushed to ballot. SaskPower would consider supporting a SAR of a MUCH MORE limited scope if it focused on adding additional language to TPL-004 related to optimizing a system's ability to slow or stop an uncontrolled cascading failure of the power system, and perhaps PRC-001 for coordination purposes.

Also, if a proposed draft standard is included with a SAR it should be commented on now, not later. If the draft is what the requestor envisions the final standard to be it should be evaluated by the industry to determine if the industry and requestor have any common ground.

This form is to be used to submit comments on the proposed Relay Loadability SAR Standards. Comments must be submitted by **February 15, 2006**. You may submit the completed form by e-mailing it to: sarcomm@nerc.com with the words "Relay Loadability SAR Comments" in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | James W. Ingleson |
| Organization: | New York ISO |
| Telephone: | 518-356-6131 |
| E-mail: | ingleson@nyiso.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☒ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
| ☒ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☐ | 5 — Electric Generators |
| ☐ SERC | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |
| ☐ NA – Not Applicable | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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Background Information:

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The available working paper includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. This working paper was prepared to assist the SAR and/or standards drafting team in the development of the proposed standard.

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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: NPCC reserves the right as stated in the SAR that determining what circuits are classified as Operationally Significant Circuits is the Region's responsibility. NPCC participating members are not in agreement with the definition as it appears in the "working paper".

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: While we agree with the applicable of the standard we also recognize that the equipment owners have concerns regarding the emergency loadibility of their equipment and the standard should recognize the ability for exceptions.

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: Generator protection considerations are different and a different set of people would be needed on the team, so this would make a strange combination with transmission system loadability. We recognize however that there are generator protections such as backup distance relay protection which require coordination between generator and tranmission relays.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: The SAR and subsequent standard should emphasize that the loadibility should apply only during emergency situations and not as a matter of normal system operations.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Bill Middaugh | |
| Organization: | Tri-State Generation and Transmission Association, Inc. | |
| Telephone: | 303-254-3433 | |
| E-mail: | bmiddaugh@tristategt.org | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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Background Information:

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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments:

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: 'Protection systems intended for protection during stable power swings' are excempted from the standard. It's been my experience that stable power swings usually call for blocking of relay operation. It would seem that 'Protection systems intended for protection during unstable power swings' ought also to be exempted from the standard.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

| **Group Comments (Complete this page if comments are from a group.)** | |
|---|---|
| **Group Name:** | NERC Standards Evaluation Subcommittee |
| **Lead Contact:** | **Bill Bojorquez** |
| **Contact Organization:** | **ERCOT** |
| **Contact Segment:** | |
| **Contact Telephone:** | **512-248-3036** |
| **Contact E-mail:** | **bbojorquez@ercot.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: The SES does believe that there is a need for a standard to address relay loadability. However, the SES urges extreme caution in moving forward with this, or any other, SAR which may arbitarily impose new requirements on the protection system of the Bulk Electric System. The SES takes note of the first sentence in the background of this SAR Comment form which to the novice reader makes it sound as if protective relays were the cause of both the 1965 and 2003 Blackout. The SES would point out that in most cases, the relays associated with these events responded properly as designed.

   Protective relaying is as much art as it is science. Also protective relay schemes are designed to work as an integrated system. It is difficult to make what might seem to be a simple beneficial change in one location and not fully consider the negative consequences this might cause in another area. Modern microproccessor relay components have made the job of determining, setting, and testing relays much simplier and more exact than in decades past. Utility personnel have spent countless hours determining the facility ratings, both normal and emergency, and the appropriate protection schemes for their lines, transformers, and other equipment in accordance with the expectations of their stakeholders (regulators, customers, and stockholders). Our bulk electric system, considered the most reliabile in the world, is a result of this effort. Great care should be taken when considering blanket changes in how relay systems are designed.

   Therefore, NERC standards related to relay loading proposed at measures of 150% of emergency rating for a period of 15 minutes may seem extreme to some. The SES questions if the SDT had considered other alternatives such as 120% for 10 minutes for example. The SES commends the SDT for the tremendous effort in bringing a proposed standard for review and looks forward to actively participate in the coming debate over this SAR.

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: The SES has concern over the wording of the proposed definition of Operationally Significant Circuits. In the definition proposed, the SDT seems to indicate the determination of Operationally Significant Circuits is the responsibility of the Regional Reliability Organization, but then the definition prescribes what types of circuits are to be included. The SES believes each Region should determine its own Operationally Significant Circuits.

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: In general, the SES agrees with the scope of the SAR. However, the SES would recommend the SDT consider adding a exemption allowance for known equipment limitations.

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: The SES believes that is proper that this proposed SAR examine relay loadability requirements for transmission lines and not address relays associated with generators with SAR. The SES believes this generator effort should be reserved for a different team in a different SAR and should move forward in parallel with this effort.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments: As noted earlier, the SES commends the SAR drafting team for their extensive work in preparing this SAR for comment and looks forward to reviewing their responses to comments received.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Peter Burke [on behalf of ATC's Rich Young] | |
| Organization: | American Transmission Company LLC ATC | |
| Telephone: | 262-506-6863 | |
| E-mail: | PBurke@atcllc.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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|---|---|---|---|
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   ☒ Yes

   ☐ No

   Comments:

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Comments:

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Comments:

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☐ Yes

☒ No

Comments:

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**Please explain in the comment area.**

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Comments:

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**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: Comments on the associated working paper:

1. R1.1.2 states the relay should not operate at or below 1.15 times the 15-minute emergency rating of the line, but the equation is identical to the one in R1.1.1 for the 4-hour rating, which indicates a limit of 1.5 times. Change “1.5” in the denominator to “1.15”, as required in Exception 1 of the “Protection System Review Program – Beyond Zone 3” dated August 2005.
2. R1.2.2.2, R1.2.6.5, R1.2.4.5 and R1.2.10.5 require operators to take immediate remedial steps, including dropping load, if the current on the circuit reaches I(emergency). This is an operating requirement, and does not belong in a relay loadability standard. Remove these requirements. There should be a requirement to that effect in the IRO or TOP standards.

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| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

| | |
|---|---|
| **Group Name:** | FRCC |
| **Lead Contact:** | **John Odom** |
| **Contact Organization:** | **FRCC** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **813-289-5644** |
| **Contact E-mail:** | **jodom@frcc.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Linda Campbell | FRCC | FRCC | 2 |
| John Mulhausen | FPL | FRCC | 1 |
| Garl Zimmerman | SECI | FRCC | 5 |
| Steve Wallace | SECI | FRCC | 4 |
| Roland Stafford | SECI | FRCC | 4 |
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Background Information:

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The purpose of the proposed Standard Authorization Request (SAR) is to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages. This transmission relay loadability SAR is submitted in response to the NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, as included in the document approved by the NERC Board of Trustees on February 10, 2004.

The available working paper includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System Outage Task Force recommendations on relaying. This working paper was prepared to assist the SAR and/or standards drafting team in the development of the proposed standard.

The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject “Relay Loadability SAR Comments” by February 15, 2006 to sarcomm@nerc.com

**1. Do you agree there is a reliability need for a standard addressing relay loadability?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: A standard addressing relay loadability is necessary to ensure that protection systems are in place to limit or stop cascading outages, while at the same time not adversely affecting the ability to use the transmission system.

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments: The SAR adequately addresses the requirements necessary to establish minimum loadability criteria for critical relays to minimize the chance of unnecessary line trips during a major transmission system disturbance.

3. **Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: The SAR covers the necessary Transmission Protection Systems and does not need to be expanded to cover relays associated with generators.

6. **Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

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- **Do not** use quotation marks in any data field.
- **Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | Jeffrey T. Baker |
| Organization: | | Cinergy |
| Telephone: | | 513-287-3368 |
| E-mail: | | jeff.baker@cinergy.com |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☒ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☒ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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Background Information:

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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

5. **Should the scope of the proposed SAR include relays associated with generators?**

   **Please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: We believe that additional or specific guidance on how to handle generators should be detailed in a separate standard.

6. **Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

This form is to be used to submit comments on the proposed Relay Loadability SAR Standards. Comments must be submitted by **February 15, 2006**. You may submit the completed form by e-mailing it to: sarcomm@nerc.com with the words “Relay Loadability SAR Comments” in the subject line. If you have questions please contact Mark Ladrow at mark.ladrow@nerc.net or by telephone at 609-452-8060.

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- **Do not** use quotation marks in any data field.
- **Do not** submit a response in an unprotected copy of this form.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |

| **Group Comments (Complete this page if comments are from a group.)** | |
|---|---|
| **Group Name:** | Southern Company - Transmission |
| **Lead Contact:** | **Marc M. Butts** |
| **Contact Organization:** | **Southern Company Services** |
| **Contact Segment:** | **1** |
| **Contact Telephone:** | **205-257-4839** |
| **Contact E-mail:** | **mmbutts@southernco.com** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Jim Viikinsalo | Southern Company Services | SERC | 1 |
| Jim Busbin | Southern Company Services | SERC | 1 |
| Phil Winston | Georgia Power | SERC | 3 |
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Background Information:

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The requestor would like to receive industry comments on this SAR and to obtain the input of the industry prior to determining the final scope of the SAR. Although a proposed draft is provided in the working paper, *please limit your comments to the subject SAR* realizing there will be future opportunity to comment on any proposed standard. Accordingly, we request your comments be included on this form and emailed with the subject "Relay Loadability SAR Comments" by February 15, 2006 to sarcomm@nerc.com

**1. Do you agree there is a reliability need for a standard addressing relay loadability?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

   **If yes, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments:

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**7. Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☐ Yes

☒ No

Comments:

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Mark Kuras |
| Organization: | PJM |
| Telephone: | 610-666-8924 |
| E-mail: | kuras@pjm.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☒ | 2 — RTOs, ISOs, Regional Reliability Councils |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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Background Information:

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1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

   **If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: Installation and coordination of relays is not something that should be dealt with with national standards. Not even sure what the name of the SAR/Standard means. Relays are not loaded or unloaded. I recommend not moving forward with this SAR.  I see no reason to move beyond the work that has already been done.

**2. Do you agree with the proposed scope of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: NERC should not get involved with this issue. Possibly a simple standard that states that protection systems shall not restrict the normal or the necessary realizable network transfer capabilities of the system is all that's needed.

**3. Do you agree with the proposed applicability of the SAR?**

**If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: An attempt is made here to circumvent the NERC definition of Transmission System by defining a Transmission Protection System Owner that goes down to 100 kV. The NERC definition of Transmission system allows regional interpretation of the voltage class. I completely disagree with this attempt.

**4. Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**If yes, please explain in the comment area.**

☐ Yes

☒ No

Comments:

**5. Should the scope of the proposed SAR include relays associated with generators?**

**Please explain in the comment area.**

☐ Yes

☒ No

Comments: I disgree with NERC dealing with this topic.

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**If yes, please explain in the comment area.**

☒ Yes

☐ No

Comments: Regional differences having to do with the definition of bulk power system should be recognized.

7. **Do you have any additional comments on this SAR you would like to include?**

**If yes, please elaborate in the comment area.**

☒ Yes

☐ No

Comments: Recommend this SAR be deleted.

## Background:

The Relay Loadability SAR Drafting Team thanks all commenters who submitted comments on the first draft of the SAR for Relay Loadability. This SAR was posted for a 30-day public comment period from January 16, 2006 - February 15, 2006. The SAR DT asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 17 sets of comments, including comments from more than 64 different people from more than 41 companies representing 6 of the 9 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the Standards Authorization Committee authorize moving this SAR forward to standard drafting.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the SAR can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/SAR_Relay_Loadability_Comments.pdf

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

| Commenter | Organization | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| William J. Smith | Allegheny Power | x | | | | | | | | |
| Ken Goldsmith | ALT | | | | | | | | | |
| Peter Burke | ATC | x | | | | | | | | |
| Dave Rudolph | BEPC | | | | | | | | | |
| Jeffrey T. Baker | Cinergy | x | | x | | | x | | | |
| Alan Gale | City of Tallahassee | | | | | x | | | | |
| Edwin Thompson | ConEdison | x | | | | | | | | |
| Charles W. Rogers | Consumers Energy Company | | | x | x | | | | | |
| Carl Kinsley | Delmarva Power and Light | x | | | | | | | | |
| Ed Davis | Entergy Services | x | | | | | | | | |
| John Mulhausen | FPL | x | | | | | | | | |
| John Odom | FRCC | | x | | | | | | | |
| Linda Campbell | FRCC | | x | | | | | | | |
| Phil Winston | Georgia Power | | | x | | | | | | |
| Dick Pursley | GRE | | | | | | | | | |
| David Kiguel | Hydro One Network | x | | | | | | | | |
| Ron Falsetti | IESO (Ontario) | | x | | | | | | | |
| Kathleen Goodman | ISO-New England | | x | | | | | | | |
| Dennis Florom | LES | | | | | | | | | |
| Donald Nelson | MA Dept of Energy and Tele. | | | | | | | | | |
| Sashi Parekh | MA Dept of Energy and Tele. | | | | | | | | | |
| Tom Mielnik | MEC | | | | | | | | | |
| Robert Coish | MHEB | | | | | | | | | |
| Terry Bilke | MISO | | x | | | | | | | |
| Joe Knight | MRO | | x | | | | | | | |
| Michael Shiavone | National Grid | x | | | | | | | | |
| Bill Bojorquez | NERC Standards Evaluation Subcommittee | | | | | | | | | |
| Greg Campoli | New York ISO | | x | | | | | | | |
| James W. Ingleson | New York ISO | | x | | | | | | | |
| George Dunn | New York Power Authority | x | | | | | | | | |
| Alan Adamson | New York State Rel. Council | | x | | | | | | | |
| Brian Hogue | NPCC | | x | | | | | | | |
| Guy Zito | NPCC | | x | | | | | | | |
| Alan Boesch | NPPD | x | | | | | | | | |
| Todd Gosnell | OPPD | | | | | | | | | |
| Mark Kuras | PJM | | x | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|
| Alvin Depew | Potomac Electric Power Co | x | | | | | | | | |
| Evan Sage | Potomac Electric Power Co | x | | | | | | | | |
| Richard Kafka | Potomac Electric Power Co | x | | | | | | | | |
| Wayne Guttormson | SaskPower | x | | | | | | | | |
| Garl Zimmerman | SECI | | | | | x | | | | |
| Roland Stafford | SECI | | | | x | | | | | |
| Steve Wallace | SECI | | | | x | | | | | |
| Jim Busbin | Southern Company Services | x | | | | | | | | |
| Jim Viikinsalo | Southern Company Services | x | | | | | | | | |
| Marc M. Butts | Southern Company Services | x | | | | | | | | |
| Wayne Guttormson | SPC | | | | | | | | | |
| Roger Champagne | TransEnergie (Quebec) | x | | | | | | | | |
| Bill Middaugh | Tri-State Generation and Transmission Association, Inc. | x | | | | | | | | |
| Darrick Moe | WAPA | | | | | | | | | |
| Jim Maenner | WPS | | | | | | | | | |
| Pam Oreschnick | XEL | | | | | | | | | |

## Index to Questions, Comments and Responses

1. **Do you agree there is a reliability need for a standard addressing relay loadability?**

**Summary Consideration:** Almost all commenters indicated that they believe there is a reliability need for a standard that addresses relay loadability. Some commenters indicated that the working paper is too prescriptive - the level of detail to be provided in the final standard will be determined based on stakeholder comments. Some commenters indicated that this topic is already addressed with the TPL series of standards, but history has shown that the TPL standards, by themselves, are not sufficient to ensure that relays will be set to prevent contributing to cascading outages

| Commenter | Yes | No | Comment |
|---|---|---|---|
| PJM (2)<br>Mark Kuras | | ✓ | Installation and coordination of relays is not something that should be dealt with with national standards. Not even sure what the name of the SAR/Standard means. Relays are not loaded or unloaded. I recommend not moving forward with this SAR. I see no reason to move beyond the work that has already been done. |
| **Response:** "Relay loadability" refers to the ability of protective relays to not operate for load currents. While the problems are being corrected, continued attention is necessary to prevent reoccurrence. Most commenters who responded to this comment form indicated that a standard is required. | | | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)<br>Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | ✓ | The MRO believes that the Relay Loadability is a serious concern and the NERC System Protection and Control Task Force (SPCTF) is to be commended on developing a good GUIDELINE for determining relay loadability settings. Based on the information contained in the Working Paper on a Proposed Transmission Relay Loadability the MRO has reservations on the appropriateness of the working paper becoming a Reliability Standard. The MRO believes that this issue could be adequately addressed through additions to existing standards to consider relay loadability. The highly prescriptive nature of the working paper is not suitable for a Reliability Standard. |
| **Response:** The level of detail necessary to address this subject suggests that this be covered in a stand alone standard as opposed to being spread across many standards. Most commenters who responded to this comment form indicated that a standard is required. Comments | | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | SaskPower believes that this issue is adequately addressed in following standards:<br>TPL-002-0 R1.3.10, TPL-003-0 R1.3.10, and TPL-004-0 R1.3.7; which require the Planning Authority and Transmission Planner to include the effects of existing and planned protection systems in their transmission planning studies in order to evaluate system performance and mitigate any deficiencies.<br>FAC-008-1 and FAC-009-1; which require Transmission Owners (TO) and Generator Owners to have a Facility Ratings Methodology and to Establish and Communicate Facility Ratings. These standards address the most limiting applicable Equipment Rating, including relay protective devices, and applicable Emergency Ratings (if the TO allows emergency overloads).<br><br>PRC-001 which requires system protection coordination among operating entities.<br>The NERC System Protection and Control Task Force (SPCTF) is to be commended on developing a good GUIDELINE for determining relay loadability settings but SaskPower has serious reservations about its appropriateness for a Reliability Standard based on the information contained in the SAR and the Working Paper on a Proposed Transmission Relay Loadability Standard. The highly prescriptive nature of the working paper is not suitable for a Reliability Standard. |
| **Response:** The level of detail necessary to address this subject suggests that this be covered in a stand alone standard as opposed to being spread across many. Most commenters who responded to this comment form indicated that a standard is required. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| City of Tallahassee (5)<br>Alan Gale | ✓ | ✓ | See comments in 2 below. |
| **Response:** See response in section 2. | | | |
| Consumers Energy (3, 4)<br>Charles W. Rogers | ✓ | | As noted in the SAR, this is an area which has contributed significantly to all major blackouts in North America. Additionally, actions directed by the NERC Planning Committee have resulted in much work on the part of the industry to resolve the problems. It's imperative that the work that has been accomplished is codified and captured within Reliability Standards. |
| **Response:** Acknowledged. | | | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5) | ✓ | | A standard addressing relay loadability is necessary to ensure that protection systems are in place to limit or stop cascading outages, while at the same time not adversely affecting the ability to use the transmission system. |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | | |
| **Response:** Acknowledged. | | | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | ✓ | | The SES does believe that there is a need for a standard to address relay loadability. However, the SES urges extreme caution in moving forward with this, or any other, SAR which may arbitarily impose new requirements on the protection system of the Bulk Electric System. The SES takes note of the first sentence in the background of this SAR Comment form which to the novice reader makes it sound as if protective relays were the cause of both the 1965 and 2003 Blackout. The SES would point out that in most cases, the relays associated with these events responded properly as designed.<br><br>Protective relaying is as much art as it is science. Also protective relay schemes are designed to work as an integrated system. It is difficult to make what might seem to be a simple beneficial change in one location and not fully consider the negative consequences this might cause in another area. Modern microproccessor relay components have made the job of determining, setting, and testing relays much simplier and more exact than in decades past. Utility personnel have spent countless hours determining the facility ratings, both normal and emergency, and the appropriate protection schemes for their lines, transformers, and other equipment in accordance with the expectations of their stakeholders (regulators, customers, and stockholders). Our bulk electric system, considered the most reliabile in the world, is a result of this effort. Great care should be taken when considering blanket changes in how relay systems are designed.<br><br>Therefore, NERC standards related to relay loading proposed at measures of 150% of emergency rating for a period of 15 minutes may seem extreme to some. The SES questions if the SDT had considered other alternatives such as 120% for 10 minutes for example. The SES commends the SDT for the tremendous effort in bringing a proposed standard for review and looks forward to actively participate in the coming debate over this SAR. |
| **Response:** Acknowledged. The drafting team did not intend to imply that protection systems were the cause of the 1965 and 2003 blackouts. Comments relating to specific requirements will be passed on to the Standards Drafting Team for consideration (when convened). The draft standard included in the working paper was intended to provide an example of requirements that could be established within the scope of this SAR, but was not intended to be the final standard. | | | |
| MAAC (2)<br>John Horakh | ✓ | | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka | ✓ | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | | | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | ✓ | | |
| NYISO (2)<br>James Ingleson | ✓ | | |
| Entergy Services, Inc. (1)<br>Ed Davis | ✓ | | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | ✓ | | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | ✓ | | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | ✓ | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | ✓ | | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | ✓ | | |
| Allegheny Power (1)<br>William J. Smith | ✓ | | |

## 2. Do you agree with the proposed scope of the SAR?

**Summary Consideration:** The comments suggest that there is some room for clarification of the proposed requirements as identified in the working paper and some room for clarification with respect to the definition of operationally significant circuits. The SAR drafting team will provide the associated Standard drafting team with these comments.

| Commenter | Yes | No | Comment |
|---|---|---|---|
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>James Ingleson – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | | ✓ | NPCC reserves the right as stated in the SAR that determining what circuits are classified as Operationally Significant Circuits is the Region's responsibility. NPCC participating members are not in agreement with the definition as it appears in the "working paper". |
| **Response:** The definition of operationally significant circuits was not included in the SAR – it was included in the working paper. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| NYISO<br>James Ingleson – NYISO | | ✓ | NPCC reserves the right as stated in the SAR that determining what circuits are classified as Operationally Significant Circuits is the Region's responsibility. NPCC participating members are not in agreement with the definition as it appears in the "working paper". |
| **Response:** As noted, the definition of operationally significant circuits was not included in the SAR – it was included in the working paper. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| PJM (2)<br>Mark Kuras | | ✓ | NERC should not get involved with this issue. Possibly a simple standard that states that protection systems shall not restrict the normal or the necessary realizable network transfer capabilities of the system is all that's needed. |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| **Response:** The analysis of all major North American blackouts, from 1967 through the current time, illustrates that the industry, left to the ideal you've suggested, will not provide adequate consideration to this issue. | | | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | | ✓ | The SES has concern over the wording of the proposed definition of Operationally Significant Circuits. In the definition proposed, the SDT seems to indicate the determination of Operationally Significant Circuits is the responsibility of the Regional Reliability Organization, but then the definition prescribes what types of circuits are to be included. The SES believes each Region should determine its own Operationally Significant Circuits. |
| **Response:** The definition of operationally significant circuits was not included in the SAR – it was included in the working paper. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| City of Tallahassee (5)<br>Alan Gale | | ✓ | The scope of the SAR as written is too much. The recommendations sited in the Blackout Reports recommended checking Zone 3 loadability only. The SAR also states that "It is imperative to the continued reliability of the North American power system that the problems of relay loadability remain corrected and that the technical solutions are properly codified in the NERC reliability standards." So from the SAR drafters own point of view, the problem has been fixed. We do not need to impose additional requirements and work on entities that are already doing their part in maintaining a reliable bulk electric system.<br><br>I agree that we should codify the requirements that we have already met for Zone 3 loadability, but question the cost vs. gain in pursuing this "monumental undertaking" for the lower voltage lines and transformers which will be an even greater undertaking than the previous one. |
| **Response:** The several reports on the blackout, including the U.S.-Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada, referenced operation of not only zone 3 relays but other load- responsive relays as well. While the problems are being corrected, continued attention is necessary to prevent re-occurrence. The lower voltage lines and transformers are not seen as a monumental undertaking as the operationally significant lines and transformers are expected to be a small subset of the total. | | | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2) | | ✓ | The MRO is disappointed to see marked up version of the SAR posted on the NERC website. SARs should be in their final format prior to being posted.<br><br>The MRO questions whether the role of the NERC Reliability Standards is to codify technical solutions. We request that the NERC-SAC clarify this role. Codifying technical solutions seems inconsistent with the intent of standards process which is to focus on WHAT is required to maintain reliability not on how to do it (i.e., technical solutions).<br><br>The suggested draft Working Paper on a Proposed Transmission Relay Loadability Standard is a good GUIDELINE for determining relay loadability settings not a Reliability Standard. The draft requirements are overly prescriptive and focus on HOW to set relays not what is required to |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)<br>Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | | maintain reliability, i.e., that each Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator should optimize their system's ability to slow or stop an uncontrolled cascading failure of the power system. The MRO believes that this optimization is best addressed through existing standards such as the TPL standards. This provides for a complete and integrated response which Transmission System Protection Owner's (TPSO) can not provide. |
| **Response:** We apologize that the marked up version was inadvertently posted.<br>The resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements. The level of detail necessary to address this subject suggests that this be covered in a stand alone standard as opposed to being spread across many standards. Most commenters who responded to this comment form indicated that a standard is required. Protective relay response time does not allow for planned operator response. The existing TPL standards have not, by themselves, prevented cascading outages and analyses of blackouts have shown that adding criteria to set limits on relay actions to optimize the ability to slow or stop an uncontrolled cascading failure of the power system is necessary. This standard is intended to facilitate the ability of the Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator to slow or stop an uncontrolled cascading failure of the power system. | | | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | SaskPower questions whether the role of the NERC Reliability Standards process is to codify technical solutions. WE REQUEST THAT THE NERC-SAC CLARIFY THIS ROLE. Codifying technical solutions seems inconsistent with the intent of standards process which is to focus on WHAT is required to maintain reliability not on HOW to do it (i.e., technical solutions). If NERC is to be codifying technical solutions WHY have we not been doing that with all of the other standards that have been developed to date?<br><br>SaskPower has the following additional comments for the Purpose/Industry Need section:<br>The purpose seems to overstate the role zone 3 played in the 2003 blackout in that relay loadability was not listed as a causal event in the final report. Quoting from the August 14, 2003, Blackout Final NERC Report, dated July 13, 2004, Section V, Conclusions and Recommendations, I. Conclusions and Recommendations, C. OTHER DEFICIENCIES, 1. Summary of Other Deficiencies Identified in the Blackout Investigation: Available system protection technologies were not consistently applied to optimize the ability to slow or stop an uncontrolled cascading failure of the power system. The effects of zone 3 relays, the lack of under-voltage load shedding, and the coordination of underfrequency load shedding and generator protection are all areas requiring further investigation to determine if opportunities exist to limit or slow the spread of a cascading failure of the system.<br><br>The reference to ongoing contributor to system disturbances is too general and should be clarified. Is it referring to all types of contingencies (Category B, C & D) or just extreme |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| | | | contingencies (Category D)? Given the references to the 2003 Blackout we assume it is meant for Category D.<br><br>SaskPower has the following additional comments for the Detailed Description section: Is the SAR intended to mitigate relay loadability impacts for all contingencies or just extreme contingencies? Is this not already covered by the TPL standards?<br><br>TPL-002-0 R1.3.10, TPL-003-0 R1.3.10, and TPL-004-0 R1.3.7; require the Planning Authority and Transmission Plannner to include the effects of existing and planned protection systems in their transmission planning studies. If system performance deficiencies are found they are supposed to mitigate them.<br><br>The SAR still seems to imply that manual operator action is preferred over automatic action, due consideration must be given to both. Relying on operator action to mitigate extreme (Category D) contingencies may be somewhat problematic.<br><br>As well, SaskPower is concerned that this SAR will limit our ability to decide how we want our system to respond to extreme contingencies. As the Planning Authority and Reliability Coordinator for Saskatchewan this is our responsibility and we feel that it is best left up to us to decide on how the relays in our system and on our tie-lines are to be set based on our system performance requirements.<br><br>The suggested draft Working Paper on a Proposed Transmission Relay Loadability Standard is a good GUIDELINE for determining relay loadability settings not a Reliability Standard. The draft requirements are overly prescriptive and focus on HOW to set relays not WHAT is required to maintain reliability, i.e., that each Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator should optimize their system's ability to slow or stop an uncontrolled cascading failure of the power system. SaskPower believes that this optimization is adequately addressed through the TPL standards. This provides for a complete and integrated response which Transmission System Protection Owner's (TPSO) can not provide.<br><br>Some general comments on the draft standard:<br>R1.1.2 uses a 15 minute emergency rating. Will system operators be able to respond within 15 minutes for a Category B, C, or D contingency (R1.1.2.2)?<br>System topologies used in the examples are rather limiting, are they system equivalents or specific topologies? |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| | | | Applying the required settings may be somewhat impractical. For example: The TPSO shall determine the maximum current flow … under ANY system condition. Suggest changing the language to any credible worst case system condition. In the case of multiple lines, this includes situations where ALL the other lines … are out of service. Is this a credible system condition? Does the TPSO have the capability to perform this analysis? Wouldn't this analysis be performed by the Planning Authority, Transmission Planner, Reliability Coordinator, or Transmission Operator?<br><br>R1.2.9. Transformer Overcurrent Protection: This requirement states that the TPSO must provide emergency loadability. SaskPower believes that Emergency Ratings for facilities are the sole responsibility of the TO (as per FAC-008 and 009) not the TPSO, and that emergency loadability is at the discretion of the TO. SaskPower also questions whether it is within the purview of this standard (or the SPCTF) to determine acceptable overloads or acceptable loss of life for ANY piece of equipment. Is this not the responsibility of the TO? As well, the protection philosophy used by the TO should be at the discretion of the TO as long as system performance criteria are met, and there has been proper coordination with the Planning Authority, Transmission Planner, Reliability Coordinator, and Transmission Operator.<br><br>R1.2.10.1 TPSO-Established Maximum Loading Capability: If the RRO is not approving Facility Ratings (FAC-008-1 and FAC-009-1) why is it approving this rating? |

**Response:** The resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements. The level of detail necessary to address this subject suggests that this be covered in a stand alone standard as opposed to being spread across many standards. Most commenters who responded to this comment form indicated that a standard is required.

Protective relay response time does not allow for planned operator response.

With respect to your comment on 'ongoing contributor to system disturbances' - some of the contingencies are even lesser contingencies than Category B.

With respect to your comment on the detailed description - Relays are in service all the time. The proposed standard is intended to give the operators time to respond to any actual or anticipated contingency that may be present.

The existing TPL standards have not, by themselves, prevented cascading outages and analyses of blackouts have shown that adding criteria to set limits on relay actions to optimize the ability to slow or stop an uncontrolled cascading failure of the power system is necessary.

Any automatic protection for response to extreme contingencies should be designed ecplicitly for that purpose and should not involve relays normally installed for fault protective purposes.

Fault protection on the interconnected power system has a wide-area impact not limited to one Reliability Coordinator or Region.

This standard is intended to facilitate the ability of the Transmission Planner, Planning Authority, Reliability Coordinator, and Transmission Operator to slow or stop an uncontrolled cascading failure of the power system.

The working paper was intended to give stakeholders a look at a possible set of requirements within the scope of the proposed SAR but the

| Commenter | Yes | No | Comment |
|---|---|---|---|
| SAR drafting team did not intend to collect specific comments on these draft requirements. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | ✓ | | The SAR adequately addresses the requirements necessary to establish minimum loadability criteria for critical relays to minimize the chance of unnecessary line trips during a major transmission system disturbance. |
| **Response:** Acknowledged. | | | |
| Consumers Energy (3, 4)<br>Charles W. Rogers | ✓ | | The draft SAR seems well prepared, and seems to accurately capture the scope of the work done thus far within the industry. |
| **Response:** Acknowledged. | | | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | ✓ | | ISO-NE believes that is it the Regions responsibility to determine what circuits are classified as "Operationally Significant Circuits." |
| **Response:** The definition of operationally significant circuits was in the working paper, not the SAR, Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| Allegheny Power (1)<br>William J. Smith | ✓ | | |
| MAAC (2)<br>John Horakh | ✓ | | |
| Entergy Services, Inc. (1)<br>Ed Davis | ✓ | | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | ✓ | | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka<br>Evan Sage<br>Alvin Depew | ✓ | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Carl Kinsley – Delmarva | | | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | ✓ | | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | ✓ | | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | ✓ | | |

### 3. Do you agree with the proposed applicability of the SAR?

**Summary Consideration:** Most commenters agreed with the applicability of the SAR. Some commenters asked for additional clarification on the proposed requirements for the RRO and DP and the SAR was revised to add these details. The proposed standard will require that each RRO have a methodology for identifying its operationally significant circuits, and will require that the RRO identify those circuits. The Transmission Owner, Generator Owner and Distribution Provider that owns a Transmission Protection System addressed by the standard will be required to comply with the transmission relay loadability criteria identified in the standard.

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>PJM (2)<br>Mark Kuras</td><td></td><td>✓</td><td>An attempt is made here to circumvent the NERC definition of Transmission System by defining a Transmission Protection System Owner that goes down to 100 kV. The NERC definition of Transmission system allows regional interpretation of the voltage class. I completely disagree with this attempt.</td></tr>
<tr><td colspan="4">Response: The NERC Glossary of Terms Used in Reliability Standards does not contain an approved definition of ‘Transmission System’. The approved definition of Bulk Electric System is:<br>As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.<br>Allowing each Region to develop a unique definition of ‘Transmission System’ does not fully consider inter-regional effects of inadvertent protective relay operation on the interconnected system. The proposed standard is intended to address functional effect of protective relays on the interconnected system. It is necessary to include some relays in addition to those installed on traditional BES elements.</td></tr>
<tr><td>MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)</td><td></td><td>✓</td><td>Nothing in the SAR explains why this should apply to the RRO or Distribution Provider.</td></tr>
</table>

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | | |
| **Response:** The proposed standard is intended to address functional effect of protective relays on the interconnected system. It is necessary to include some relays in addition to those installed on traditional Transmission System elements. Some of these relays may be on equipment owned by the DP. It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include these clarifications. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ✓ | The proposed criteria for determining Operationally Significant Circuits should be more clear and concise. As written, misinterpretation is probable.<br><br>1. Does the term "Flowgates" refer to those facilities in the NERC Book of Flowgates? If so, please so state. If not, what is the definition of "Flowgates" as a proper term?<br><br>2. The phrase "All circuits that are elements of system operating limits" means what. Every transmission line has a rating that, when exceeded, constitutes a system operating limit. This seems to leave the door open to saying that every possible combination of outaged and monitor elements could be considered operationally significant. It would be more practical to state that " All circuits that are elements of a reported SOL violation or IROL violation including both the monitored and outage elements"<br><br>3. With respect to the offsite power supply to nuclear plants, what is the criteria for "adverse impact"? If outage of a particular circuit drops the voltage at the offsite power bus for a nuclear plant from 1.02 per unit to 1.00 per unit, does this constitute an adverse impact? Hopefully not. Such would be impractical. A recommended alternative is "Any circuit, when outaged, that causes the voltage at the off-site power bus at a nuclear bus to exceed established operating limits". |
| **Response:** All of your comments/questions pertain to clarification of the working paper, rather than the SAR. Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | Nothing in the SAR explains why this should apply to the RRO. The RRO is referenced in the draft standard (which we are not supposed to comment on). |
| **Response:** It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include this clarification. | | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | ✓ | | In general, the SES agrees with the scope of the SAR. However, the SES would recommend the SDT consider adding a exemption allowance for known equipment limitations. |
| **Response:** The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. | | | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy<br>Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>James Ingleson – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | ✓ | | While we agree with the applicable of the standard we also recognize that the equipment owners have concerns regarding the emergency loadibility of their equipment and the standard should recognize the ability for exceptions.<br><br>The TPSO definition in the whitepaper should be included in the SAR. |
| **Response:** The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. TPSO was defined in the SAR. | | | |
| NYISO<br>James Ingleson – NYISO | ✓ | | While we agree with the applicable of the standard we also recognize that the equipment owners have concerns regarding the emergency loadibility of their equipment and the standard should recognize the ability for exceptions. |
| **Response:** The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. | | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Consumers Energy (3, 4)<br>Charles W. Rogers | ✓ | | All listed entities have a role in addressing the problems. It's only unfortunate that there isn't an entity within the Functional Model which is specifically and completely responsible for all facets of protective systems. |
| **Response:** Acknowledged. | | | |
| MAAC (2)<br>John Horakh | ✓ | | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka<br>Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | ✓ | | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | ✓ | | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | ✓ | | |
| City of Tallahassee (5)<br>Alan Gale | ✓ | | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | ✓ | | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | ✓ | | |
| FRCC (2)<br>John Odom | ✓ | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | ✓ | | |
| Allegheny Power (1)<br>William J. Smith | ✓ | | |

4. **Are you aware of any commercial considerations that might require a concurrent NAESB action associated with the proposed SAR?**

**Summary Consideration:** No commenters suggested the need for any concurrent NAESB action associated with the proposed standard.

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Consumers Energy (3, 4)<br>Charles W. Rogers | | ✓ | This is wholly a technical issue related to the reliability of the electrical system. There is, of course, a cost issue related to continued compliance, but this isn't a commercial issue. |
| **Response:** Acknowledged. | | | |
| MAAC (2)<br>John Horakh | | ✓ | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka<br>Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | | ✓ | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>James Ingleson – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | | ✓ | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| NYISO<br>James Ingleson – NYISO | | ✓ | |
| PJM (2)<br>Mark Kuras | | ✓ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ✓ | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | | ✓ | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | | ✓ | |
| City of Tallahassee (5)<br>Alan Gale | | ✓ | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | | ✓ | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | | ✓ | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | ✓ | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2) | | ✓ | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)<br>Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | | ✓ | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | | ✓ | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | |
| Allegheny Power (1)<br>William J. Smith | | ✓ | |

## 5. Should the scope of the proposed SAR include relays associated with generators?

**Summary Consideration:** Most commenters indicated that the proposed standard should not include relays associated with generators so the SAR drafting team did not modify the SAR to address additional generator protection.

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Pepco Holdings, Inc. (1)<br>Richard Kafka<br>Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | | ✓ | The SAR properly excludes generation protection systems. We acknowledge that the SAR should (and does) include transmission protection systems located (and possibly owned) by the Generation Own. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | | ✓ | Although NPCC's participating members believe that for the purposes of this SAR the relays assocciated with generators should not be included in the scope, it is important that the issue of coordination between generator and transmission system protection be addressed elsewhere in the NERC standards. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| NYISO<br>James Ingleson – NYISO | | ✓ | Generator protection considerations are different and a different set of people would be needed on the team, so this would make a strange combination with transmission system loadability. We recognize however that there are generator protections such as backup distance relay protection |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| | | | which require coordination between generator and transmission relays. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| PJM (2)<br>Mark Kuras | | ✓ | I disgree with NERC dealing with this topic. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| Consumers Energy (3, 4)<br>Charles W. Rogers | ✓ | | Only to the extent that generator FAULT PROTECTIVE relays provide some degree of remote backup protection for transmission-voltage-level faults, and respond in such a way as to limit loading on the generator, generator step up transformer, or connection of the generator step up transformer to the transmission system. The applicability is well described in clause R1.2.5 of the posted Working Paper, and well limited by clause 4.3 of the Working Paper. This area of generator protection probably ultimately needs to be comprehensively addressed, but to do so would be premature based on the knowledge base within NERC and within the industry. Many other factors will probably also need to be considered to move forward to an increased degree on consideration of generator protection. |
| **Response:** Thank you for your comments relative to generator protection. In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. Your comments will be considered if/when a SAR addressing generator protection is developed. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | | None |
| ISO New England, Inc. (2)<br>Kathleen Goodman | | ✓ | This should be a future consideration for a staged implementation. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | | ✓ | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| City of Tallahassee (5) | | ✓ | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Alan Gale | | | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | | ✓ | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | | ✓ | We believe that additional or specific guidance on how to handle generators should be detailed in a separate standard. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | ✓ | The SAR covers the necessary Transmission Protection Systems and does not need to be expanded to cover relays associated with generators. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2) | | ✓ | The working paper should not be turned into a Standard. |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)<br>Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. The issue of the need for this standard was addressed in our response to your comments in question 1. | | | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | | ✓ | The SES believes that is proper that this proposed SAR examine relay loadability requirements for transmission lines and not address relays associated with generators with SAR. The SES believes this generator effort should be reserved for a different team in a different SAR and should move forward in parallel with this effort. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | The working paper should not be turned into a Standard. |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. The issue of the need for this standard was addressed in our response to your comments in question 1. | | | |
| Allegheny Power (1)<br>William J. Smith | | ✓ | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |
| MAAC (2)<br>John Horakh | ✓ | | Relays that do more than trip a single genrator should be included. |
| **Response:** Thank you for your comments relative to generator protection. In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. Your comments will be considered if/when a SAR addressing generator protection is developed. | | | |
| American Transmission Company LLC ATC (1) | ✓ | | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Peter Burke [on behalf of ATC's Rich Young] | | | |
| **Response:** In response to the prevailing comments the SAR drafting team has decided not to expand this SAR to include additional consideration of generator protection. | | | |

**6. Are you aware of any regional differences that should be identified as part of the development of the standard?**

**Summary Consideration:** No specific regional differences were identified by commenters. Some commenters indicated that regional differences may be identified once the standard is developed.

| Commenter | Yes | No | Comment |
|---|---|---|---|
| PJM (2)<br>Mark Kuras | ✓ | | Regional differences having to do with the definition of bulk power system should be recognized. |
| **Response:** This standard does not rely on a Regional definition of bulk power system. | | | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | ✓ | | ISO-NE believes that because there are no uniform standards for rating facilities, such as conductors, transformers, etc. that have been accepted nationwide, it will be difficult to have all responsible entities comply with this Standard. The ISO believes that each Region must and should determine it's own standards for rating facilities, espeically if it pertains to determining which circuits are "operationally significant." |
| **Response:** Your comment will be passed on to the standard drafting team for consideration (when convened). As envisioned, the RRO will establish a methodology for determining which of the circuits within its area are operationally significant. | | | |
| Consumers Energy (3, 4)<br>Charles W. Rogers | | ✓ | The clauses within the Working Paper seem to represent the major system issues endemic on all North American systems. |
| **Response:** Acknowledged. | | | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2) | | ✓ | Without specific information about the content of the standard it is difficult to determine the necessity for Regional Differences. |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | | | |
| **Response:** Acknowledged. | | | |
| MAAC (2)<br>John Horakh | | ✓ | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka<br>Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | | ✓ | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | | ✓ | |
| NYISO<br>James Ingleson – NYISO | | ✓ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ✓ | |
| Southern Co. – Transm. (1) | | ✓ | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | | | |
| City of Tallahassee (5)<br>Alan Gale | | ✓ | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | | ✓ | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | | ✓ | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | ✓ | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | | ✓ | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | | ✓ | |
| SaskPower (1)<br>Wayne Guttormson | | ✓ | |
| Allegheny Power (1)<br>William J. Smith | | ✓ | |

7. **Do you have any additional comments on this SAR you would like to include?**

| Commenter | Yes | No | Comment |
|---|---|---|---|
| NYISO<br>James Ingleson – NYISO | ✓ | | The SAR and subsequent standard should emphasize that the loadibility should apply only during emergency situations and not as a matter of normal system operations. |
| **Response: Agreed.** The proposed standard is not intended to increase system ratings but instead it provides system operators with the opportunity to respond to actual or projected system overloads during any system operating condition. . | | | |
| PJM (2)<br>Mark Kuras | ✓ | | Recommend this SAR be deleted. |
| **Response:** See the response to your comments on question 1. Most commenters supported this SAR. | | | |
| Consumers Energy (3, 4)<br>Charles W. Rogers | ✓ | | It's a superbly prepared SAR, and should go forward as is. Additionally, the Working Paper seems to represent an excellent first draft for the standard, and the process would probably be best served if the Standard Drafting Team, upon formation, would post the Working Paper as Draft 1 of the standard. |
| **Response:** Acknowledged. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | ✓ | | The draft standard will apply to transmission lines operated 200 kV and above. This assumes that all of these circuits are operationally significant and that may not be the case. The operationally significant criteria should be applied to all lines 100 kV and above. |
| **Response:** The original recommendations to include circuits 200 kV and above came from the blackout team investigative analysis. The NERC BOT approved these recommendations on February 4, 2004 and assigned implementation to the appropriate NERC committees. The proposed standard adopts these recommendations and adds the lower voltage operationally significant circuits as per Recommendation 21 of the US-Canada Final Report on the Blackout published April, 2004. | | | |
| ISO New England, Inc. (2)<br>Kathleen Goodman | ✓ | | We feel that the definitions of TPSO and voltage classifications as noted on page SAR-6, should be included as part of the Standard. Furthermore, the Standard definitions should align with the working paper definitions. |
| **Response:** Comments relating to the working paper will be passed on to the Standards Drafting Team for consideration (when convened). The definition of TPSO in the SAR will carry over to the standard. The final definition of other terms developed with the standard will need to meet stakeholder consensus and this SAR drafting team cannot guarantee that they will match the definitions in the working paper. | | | |
| Tri-State Generation and Transmission Association, Inc. (1)<br>Bill Middaugh | ✓ | | Protection systems intended for protection during stable power swings' are exempted from the standard. It's been my experience that stable power swings usually call for blocking of relay operation. It would seem that 'Protection systems intended for protection during unstable power swings' ought also to be exempted from the standard. |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| **Response:** Relay systems are in service all the time - protection systems intended for protection during unstable power swings may also respond to heavy loads during steady-state operating conditions and thus cannot be excluded from this standard. If you disagree, please provide more details to the standard drafting team for their consideration. | | | |
| MRO (2)<br>Jim Maenner<br>Al Boesch – NPPD (2)<br>Terry Bilke – MISO (2)<br>Bob Coish – MHEB (2)<br>Dennis Florom – LES (2)<br>Ken Goldsmith – ALT (2)<br>Todd Gosnell – OPPD (2)<br>W. Guttormson – SPC (2)<br>Tom Mielnik – MEC (2)<br>Darrick Moe – WAPA (2)<br>P. Oreschnick – XEL (2)<br>Dick Pursley – GRE (2)<br>Dave Rudolph – BEPC (2)<br>Joe Knight – MRO (2)<br>27 additional MRO members not listed above. | ✓ | | Based on the draft standard that is included as a working paper the MRO would support a SAR of more limited scope if it focused on adding additional language to existing standards such as TPL-004 related to optimizing a system's ability to slow or stop an uncontrolled cascading failure of the power system. |
| **Response:** See the response to your comments on question 1. | | | |
| American Transmission Company LLC ATC (1)<br>Peter Burke [on behalf of ATC's Rich Young] | ✓ | | Comments on the associated working paper:<br>1. R1.1.2 states the relay should not operate at or below 1.15 times the 15-minute emergency rating of the line, but the equation is identical to the one in R1.1.1 for the 4-hour rating, which indicates a limit of 1.5 times. Change “1.5” in the denominator to “1.15”, as required in Exception 1 of the “Protection System Review Program – Beyond Zone 3” dated August 2005.<br>2. R1.2.2.2, R1.2.6.5, R1.2.4.5 and R1.2.10.5 require operators to take immediate remedial steps, including dropping load, if the current on the circuit reaches I(emergency). This is an operating requirement, and does not belong in a relay loadability standard. Remove these requirements. There should be a requirement to that effect in the IRO or TOP standards. |
| **Response:** Acknowledged. Comment will be passed on to the Standards Drafting Team for consideration (when convened). | | | |
| SaskPower (1)<br>Wayne Guttormson | ✓ | | SaskPower would vote NO on this draft standard if it were pushed to ballot. SaskPower would consider supporting a SAR of a MUCH MORE limited scope if it focused on adding additional language to TPL-004 related to optimizing a system's ability to slow or stop an uncontrolled |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| | | | cascading failure of the power system, and perhaps PRC-001 for coordination purposes. Also, if a proposed draft standard is included with a SAR it should be commented on now, not later. If the draft is what the requestor envisions the final standard to be it should be evaluated by the industry to determine if the industry and requestor have any common ground. |
| **Response:** See the response to your comment on question 1. The draft standard was included to provide commenters with an idea of the intended scope of the associated standard but was not intended to be presented as the 'final standard'. | | | |
| NERC Standards Evaluation Committee<br>Bill Bojorquez – ERCOT | | ✓ | As noted earlier, the SES commends the SAR drafting team for their extensive work in preparing this SAR for comment and looks forward to reviewing their responses to comments received. |
| **Response:** Acknowledged. | | | |
| NPCC CP9, Reliability Standards Working Group<br>K. Goodman – ISONE<br>M. Schiavone – Ngrid<br>R. Champagne – TransÉnergie<br>David Kiguel – Hydro One<br>Ron Falsetti – IESO<br>Edwin Thompson – ConEd<br>Don Nelson – MA Dept. of Tel. and Energy Shashi Parekh – MA Dept. of Tel. and Energy<br>Alan Adamson – NYSRC<br>Greg Campoli – NYISO<br>Brian Hogue – NPCC<br>Guy Vito – NPCC | | ✓ | The SAR and subsequent standard should emphasize that the loadibility should apply only during emergency situations and not as a matter of normal system operations. |
| **Response:** System Operators have the responsibility to operate the system within established limits. Protective relaying should be applied so as to provide the operators the ability to respond according to their responsibility. The proposed standard of establishing relay loadability criteria should not be seen as increasing the ability of the system to carry load but instead should allow the operators time to respond accordingly. | | | |
| MAAC (2)<br>John Horakh | | ✓ | |
| Pepco Holdings, Inc. (1)<br>Richard Kafka | | ✓ | |

| Commenter | Yes | No | Comment |
|---|---|---|---|
| Evan Sage<br>Alvin Depew<br>Carl Kinsley – Delmarva | | | |
| Southern Co. – Transm. (1)<br>Marc M. Butts<br>Jim Busbin – SOCO (1)<br>Jim Viikinsalo – SOCO (1)<br>Phil Winston – GA PWR (3) | | ✓ | |
| City of Tallahassee (5)<br>Alan Gale | | ✓ | |
| Cinergy (1, 3, 6)<br>Jeffrey T. Baker | | ✓ | |
| FRCC (2)<br>John Odom<br>Linda Campbell<br>John Mulhausen – FPL ( 1)<br>Garl Zimmerman – SECI (5)<br>Steve Wallace – SECI (4)<br>Roland Stafford – SECI (4) | | ✓ | |
| Allegheny Power (1)<br>William J. Smith | | ✓ | |

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

April 21, 2006

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

**Announcement: Comment Periods and Drafting Team Self-nominations Open April 21**

**The Standards Authorization Committee (SAC) announces the following standards actions:**

**Missing Measures and Compliance Elements Standards Posted for 30-day Comment Period (April 21–May 21)**

The Missing Measures and Compliance Elements Standard Drafting Team has completed adding measures and compliance elements to 20 Version 0 standards that were approved without these elements. The drafting team will make conforming changes based on stakeholder comments and then post the second drafts of these standards for a 45-day comment period. Please use this comment form (Excel spreadsheet) to provide comments on this set of standards.

**Violation Risk Factors Survey Posted for 45-day Comment Period (April 21–June 4)**

The Violation Risk Factors SAR Drafting Team developed a survey to collect stakeholder feedback on proposed ratings of the reliability-related risk (risk factors) of violating each requirement in each approved standard. Please note that we're using Excel because of the large amount of data requested. These reliability-related risks are proposed for use when determining a penalty or sanction for a violation of that requirement. Please use this comment form to provide feedback on the proposed matrix of violation risk factors.

**Nominations for Drafting Teams Open (April 21–May 3)**

The SAC is soliciting drafting team members to serve on the Violation Risk Factors Standard Drafting Team. The drafting team will use stakeholder feedback to create the initial violation risk assigned to each NERC standard requirement. These violation risk factors would be used for the initial basis for determining enforcement action for future violations. If you are interested in volunteering for this drafting team, please submit this nomination form.

The SAC is soliciting drafting team members to serve on the Relay Loadability Standard Drafting Team. The formation of this drafting team is contingent upon the SAC authorizing the Relay Loadability SAR to move forward to standard drafting. The Relay Loadability standard will establish minimum loadability criteria for relays to minimize the chance of unnecessary line trips during a major system disturbance. If you are interested in volunteering for this drafting team, please submit this nomination form.

**Notice to Forward Standards to NERC Board of Trustees**

This announcement also serves as 30-days notice from the SAC to the registered ballot body of the committee's intention to forward EOP-004 Disturbance Reporting and IRO-006 (TLR Levels 3b and 4) Reliability Coordination – Transmission Loading Relief standards — if they are approved by their respective ballot pools — to the NERC Board of Trustees for approval.

**Standards Development Process**

The NERC posting and balloting procedures are described in the *Reliability Standards Process Manual*, which contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Please send questions to Maureen Long at maureen.long@nerc.net, or call 813-468-5998.

Sincerely,

*Maureen E. Long*

Maureen E. Long
Standards Process Manager

cc: Registered Ballot Body Registered Users
Standards Group
NERC Roster

Please return this form to sarcomm@nerc.com by May 3, 2006. For questions, please contact Richard Schneider at 609-452-8060 or Richard.Schneider@nerc.net.

This drafting team will likely hold its initial meeting in late May 2006 to begin drafting the proposed standards. The complete meeting schedule has not been determined yet. It is expected the teams will meet several times in 2006 including face-to-face or conference call/Webex meetings. **All candidates should be prepared to participate actively at these meetings.**

| | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Address: | | |
| Office Telephone: | | |
| E-mail: | | |
| **Please briefly describe your experience and qualifications to serve on the Relay Loadability Standard Drafting Team. Candidates should have expertise in one or more of the following areas: transmission planning, protective relaying, transmission design, or generation operations. Previous experience developing or applying NERC or IEEE standards is beneficial, but not a requirement.** | | |
| **I represent the following NERC Reliability Region(s) (check all that apply):** | **I represent the following Industry Segment (check one):** | |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
| ☐ NPCC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ RFC | ☐ | 5 — Electric Generators |
| ☐ SERC | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ SPP | ☐ | 7 — Large Electricity End Users |
| ☐ WECC | ☐ | 8 — Small Electricity End Users |

| | | |
|---|---|---|
| ☐ NA – Not Applicable | ☐ | 9 — Federal, State, and Provincial Regulatory or other Government Entities |

**Which of the following Function(s)[1] do you have expertise or responsibilities:**

| | |
|---|---|
| ☐ Reliability Coordinator | ☐ Transmission Service Provider |
| ☐ Balancing Authority | ☐ Transmission Owner |
| ☐ Interchange Authority | ☐ Load Serving Entity |
| ☐ Planning Authority | ☐ Distribution Provider |
| ☐ Transmission Operator | ☐ Purchasing-selling Entity |
| ☐ Generator Operator | ☐ Generator Owner |
| ☐ Transmission Planner | ☐ Resource Planner |
| | ☐ Market Operator |

**Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.**

| | |
|---|---|
| Name: | Office Telephone: |
| Organization: | E-mail: |
| Name: | Office Telephone: |
| Organization: | E-mail: |

[1] These functions are defined in the NERC Glossary of Terms, which is downloadable from the NERC Web site.

E-mail completed form to mark.ladrow@nerc.net

# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Transmission Relay Loadability |
| Request Date | January 09, 2006 |
| Revised: April 26, 2006 | |

| SAR Requester Information | | SAR Type (Check box for each one that applies.) | |
|---|---|---|---|
| Name | NERC System Protection and Controls Task Force (SPCTF) | ☒ | New Standard |
| Primary Contact<br>Charles Rogers, Chairman of SPCTF | | ☐ | Revision to existing Standard |
| Telephone<br>Fax | (517) 788-0027<br>(517) 788-0917 | ☐ | Withdrawal of existing Standard |
| E-mail | cwrogers@cmsenergy.com | ☐ | Urgent Action |

Purpose/Industry Need

Protective relays have contributed to virtually all major system disturbances including the Northeast Blackout of 1965, the New York Blackout of 1977, the WECC Blackouts of 1996, and the Blackout of August 14, 2003. During the 2003 blackout, relay loadability was found to have played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by "zone 3" relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

As a result, recommendations were made for the review of relay settings and the mitigation of zone 3 relays operating under load included in NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.-Canada Power System Outage Task Force Recommendation 21a, *Make More Effective and Wider Use of System Protection Measures*.

Over the last 18 months, the electric industry has been reviewing protection systems to determine their conformance with the loadability criteria set forth in those recommendations. The monumental effort to review and mitigate relay loadability issues done by the industry is to be applauded. However, those improvements to the protection systems cannot be allowed to lapse if relay loadability problems are to cease to be an ongoing contributor to system disturbances.

It is imperative to the continued reliability of the North American power system that the problems of relay loadability remain corrected and that the technical solutions are properly codified in NERC reliability standards.

### *Reliability Functions*

| The Standard will Apply to the Following Functions *(Check box for each one that applies.)* | | |
|---|---|---|
| ☒ | Regional Reliability Organization | Ensures the reliability of the bulk electric system within its Region. |
| ☐ | Reliability Authority | Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority. |
| ☐ | Balancing Authority | Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time |
| ☐ | Interchange Authority | Authorizes valid and balanced Interchange Schedules |
| ☐ | Planning Authority | Plans the bulk electric system |
| ☐ | Resource Planner | Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area. |
| ☐ | Transmission Planner | Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area. |
| ☐ | Transmission Service Provider | Provides transmission services to qualified market participants under applicable transmission service agreements |
| ☒ | Transmission Owner | Owns transmission facilities |
| ☐ | Transmission Operator | Operates and maintains the transmission facilities, and executes switching orders |
| ☒ | Distribution Provider | Provides and operates the “wires” between the transmission system and the customer |
| ☒ | Generator Owner | Owns and maintains generation unit(s) |
| ☐ | Generator Operator | Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services |
| ☐ | Purchasing-Selling Entity | The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required |
| ☐ | Market Operator | Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch. |
| ☐ | Load-Serving Entity | Secures energy and transmission (and related generation services) to serve the end user |

### *Reliability and Market Interface Principles*

| **Applicable Reliability Principles** *(Check box for each one that applies..)* | |
|---|---|
| ☒ | 1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards. |
| ☐ | 2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. |
| ☐ | 3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably. |
| ☒ | 4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented. |
| ☒ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems. |
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☒ | 7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis. |

| **Does the proposed Standard comply with all of the following Market Interface Principles?** *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)* |
|---|
| 1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes |
| 2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes |
| 3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes |
| 4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes |
| 5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes |

**Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)**

**Scope**

The scope of the proposed standard would be to codify the relay loadability criteria and their implementation in accordance with the tenets of NERC Blackout Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada *Power System Outage* Task Force Recommendation 21A, *Make More Effective And Wider Use Of System Protection Measures,* to ensure that protection systems and settings shall not limit transmission loadability, nor contribute to cascading outages.

**Applicability**

[Definition of Transmission Protection System Owners (TPSOs)
Entities that own and/or operate protective relaying systems applied to protect transmission facilities operated at 100 kV and above, including transformer banks with low-voltage terminals operated at 100 kV and above.]

1. This standard pertains to phase protection systems applied to:
    a. Transmission lines operated at 200 kV and above
    b. Transmission lines operated at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
    c. Transformers with low voltage terminals connected at 200 kV and above voltage levels
    d. Transformers with low voltage terminals connected at 100 kV to 200 kV, identified by the Region as Operationally Significant Circuits.
2. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
    a. Phase distance
    b. Out-of-step tripping
    c. Out-of-step blocking
    d. Switch-on-to-fault
    e. Overcurrent relays
    f. Communications aided protection schemes including but not limited to:
        i. Permissive overreach transfer trip (POTT)
        ii. Permissive under-reach transfer trip (PUTT)
        iii. Directional comparison blocking (DCB)
3. The following protection systems are excluded from requirements of this standard:
    a. Relay elements that are only enabled when other relays or associated systems fail.
        i. Overcurrent elements that are only enabled during loss of potential conditions.
        ii. Elements that are only enabled during a loss of communications.
    b. Protection systems intended for the detection of ground fault conditions

c. Protection systems intended for protection during stable power swings.

d. Generator protection relays that are susceptible to load.

e. Relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

4. This standard applies to the following entities:

   a. Regional Reliability Organizations.

   b. Transmission Owners that are Transmission Protection System Owners (TPSOs).

   c. Generation Owners that are TPSOs.

   d. Distribution Providers that are TPSOs.

5. The standard will require that each RRO have a documented methodology for identifying its Operationally Significant Circuits and will require that each Regional Reliability Organization have a list of operationally significant circuits.

6. The standard will require that each Transmission Owner, Generation Owner and Distribution Provider that is a Transmission Protection System Owner, comply with the transmission relay loadability criteria identified in the standard.

The standard should incorporate relay loadability criteria for all phase distance (including zone 3) and overcurrent relays, as well as, any protective functions which could trip with or without time delay, on normal or emergency load current. The Standard should specifically exclude: relay elements that are only enabled when other relays or associated systems fail, protection systems intended for the detection of ground fault conditions, protection systems intended for protection during stable power swings, generator protection relays that are susceptible to load, relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

The proposed standard should consider that during emergency loading conditions on the transmission system, the system operators should be making the human decision to open overloaded facilities, if conditions so warrant. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion should be specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. The system operator actions may include manual removal of the transmission circuit from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).

**Additional Information**

The *Working Paper on a Proposed Transmission Relay Loadability Standard*, prepared by the System Protection and Controls Task Force includes a proposed draft Transmission Relay Loadability Standard that codifies the relay loadability criteria prescribed in the NERC and U.S.-Canada Power System

Outage Task Force recommendations on relaying. It is available on the NERC SPCTF website using the hotlink above. That working paper was prepared to assist the Standards Authorization Committee and its SAR and/or standards drafting team in the development of the proposed standard. This working paper takes full advantage of the recent experience of applying those criteria to the EHV transmission system (200 kV and above) and ongoing work on the 100–200 kV Operationally Significant Circuits.

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## *Related Standards*

| Standard No. | Explanation |
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## *Related SARs*

| SAR ID | Explanation |
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## *Regional Differences*

| Region | Explanation |
|---|---|
| ERCOT | |
| FRCC | |
| MRO | |
| NPCC | |
| RFC | |
| SERC | |
| SPP | |
| WECC | |

E-mail completed form to mark.ladrow@nerc.net

# Standard Authorization Request Form

| | |
|---|---|
| Title of Proposed Standard | Transmission Relay Loadability |
| Request Date | January 09, 2006 |
| Revised: April 26, 2006 | |

| SAR Requester Information | | SAR Type (Check box for each one that applies.) | |
|---|---|---|---|
| Name | NERC System Protection and Controls Task Force (SPCTF) | ☒ | New Standard |
| Primary Contact | Charles Rogers, Chairman of SPCTF | ☐ | Revision to existing Standard |
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## Purpose/Industry Need

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    e. Overcurrent relays
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3. The following protection systems are excluded from requirements of this standard:
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    b. Protection systems intended for the detection of ground fault conditions

c. Protection systems intended for protection during stable power swings.

d. Generator protection relays that are susceptible to load.

e. Relays elements used only for special protection systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

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   b. Transmission Owners that are Transmission Protection System Owners (TPSOs).
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**Additional Information**

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## *Related Standards*

| Standard No. | Explanation |
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## *Related SARs*

| SAR ID | Explanation |
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## *Regional Differences*

| Region | Explanation |
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| ERCOT | |
| FRCC | |
| MRO | |
| NPCC | |
| RFC | |
| SERC | |
| SPP | |
| WECC | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC approves SAR for posting on January 9, 2006.
2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
3. The SAC approves development of the standard on May 12, 2006.
4. The JIC assigns development of the standard to NERC on June 15, 2006.

**Description of Current Draft:**

This is a 45-day (August 16–September 29) posting of the initial draft of the Transmission Relay Loadability Standard. It codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.*

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Consider and post response to comments. | October 16, 2006 |
| 2. Post for 30-day comment period. | October 16–November 14, 2006 |
| 3. Post for 30-day pre-ballot period. | November 20–December 19, 2006 |
| 4. Conduct first ballot. | December 20, 2006–January 3, 2006 |
| 5. Consider and post response to comments on first ballot. | January 8, 2007 |
| 6. Conduct second ballot. | January 9–18, 2007 |
| 7. BOT Adoption. | February 1, 2007 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

None.

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability.

4. **Applicability:**

   **4.1.** Transmission Owners with phase protection systems as described in Attachment A, applied to:

   **4.1.1** Transmission lines operated at 200 kV and above.

   **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Regional Reliability Organization as critical to the reliability of the electric system.

   **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

   **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Regional Reliability Organization as critical to the reliability of the electric system.

   **4.2.** Generator Owners with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4.

   **4.3.** Distribution Providers with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4:

5. **(Proposed) Effective Dates:**

   **5.1.** For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008.

   **5.2.** For circuits described in 4.1.2 and 4.1.4 above — July 1, 2008.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15 minute Facility Rating of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit bus voltage at each end of the line.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes)[1].

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays so they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature.

[1] This requirement is based on a distance relay maximum torque angle (and thus the impedance angle) approaching 90-degrees, while the relevant load current angle is 30-degrees. In addition, if there is a weak source "behind" the relay, the fault magnitude in amperes may be limited while the distance to a fault, as measured by a distance relay, is not.

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator(s) prior to using the criteria established in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 as listed below. The approvals are required for each circuit terminal using the listed criteria. [Risk Factor: Lower]

**R2.1.** The Transmission Owner, Generator Owner, or Distribution Provider that uses the criteria described in R1.6, R1.7, R1.8, or R1.9 shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator prior to using these criteria.

**R2.2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses the criteria described in Requirement 1.12, shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator prior to using this criteria.

**R2.3.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in Requirement 1.13, shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator before using the circuit capability and shall use the circuit capability as the Facility Rating of the circuit.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in Requirement 1.1 through R1.13.

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the use of the criteria was approved by its associated Regional Reliability Organization and Reliability Coordinator before being used and shall have evidence that the circuit rating is used as the Facility Rating of that circuit.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

**1.1.1** Regional Reliability Organization.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4.** Additional Compliance Information

The Transmission Owner, Generator Owner, and Distribution Provider shall each demonstrate compliance through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2.** Levels of Non-Compliance

**2.1. Level 1:**

**2.1.1** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that approval was obtained in accordance with R2.

**2.2. Level 2:**

**2.2.1** Evidence that relay settings comply with one of the criteria in R1.1 through R1.13 exists but is incomplete or incorrect.

**2.3. Level 3:**

**2.3.1** Relay settings do not comply with transmission loadability criteria in R1, and the relay settings were causal to a Reportable Disturbance.

**2.4. Level 4:**

**2.4.1** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

## E. Regional Differences

**1.** None

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Attachment A

**1.1.** This standard addresses any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.1** Phase distance

**1.1.2** Out-of-step tripping

**1.1.3** Out-of-step blocking

**1.1.4** Switch-on-to-fault

**1.1.5** Overcurrent relays

**1.1.6** Communications aided protection schemes including but not limited to:

**1.1.6.1** Permissive overreach transfer trip (POTT)

**1.1.6.2** Permissive under-reach transfer trip (PUTT)

**1.1.6.3** Directional comparison blocking (DCB)

**1.1.6.4** Directional comparison unblocking (DCUB)

**1.2.** The following protection systems are <u>excluded</u> from requirements of this standard:

**1.2.1** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**1.2.2** Protection systems intended for the detection of ground fault conditions.

**1.2.3** Protection systems intended for protection during stable power swings.

**1.2.4** Generator protection relays that are susceptible to load.

**1.2.5** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

NORTH AMERICAN
ELECTRIC
RELIABILITY
COUNCIL

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August 16, 2006

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

**Announcement: Comment Period Opens for Transmission Relay Loadability Standard**

The Standards Authorization Committee (SAC) announces the following standards actions:

**Transmission Relay Loadability Standard (August 16–September 29, 2006)**
The Transmission Relay Loadability Standard Drafting Team posted the first draft of its standard for a 45-day comment period from August 16 through September 29, 2006. This standard codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.* Please use the comment form to provide comments on this standard.

**Standards Development Process**
The NERC posting and balloting procedures are described in the *Reliability Standards Development Procedure*, which contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Please send questions to Maureen Long at maureen.long@nerc.net, or call 813-468-5998.

Sincerely,

Maureen E. Long

Maureen E. Long
Standards Process Manager

cc: Registered Ballot Body Registered Users
Standards Group
NERC Roster

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

The proposed standard will become effective on:

- January 1, 2008 for transmission lines operated at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.
- July 1, 2008 for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, as designated by the regional reliability organization as critical to the reliability of the electric system in the region.
- Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

# PRC-023 Reference

## Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Council

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

***Version 1.0***

***August 14, 2006***

# Table of Contents

# Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Generator protection relays
   - 2.4. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

# Requirements Reference Material

## R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

## R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{rating}$ = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating ($I_{rating}$) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

## R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating ($I_{rating}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

## R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

### R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

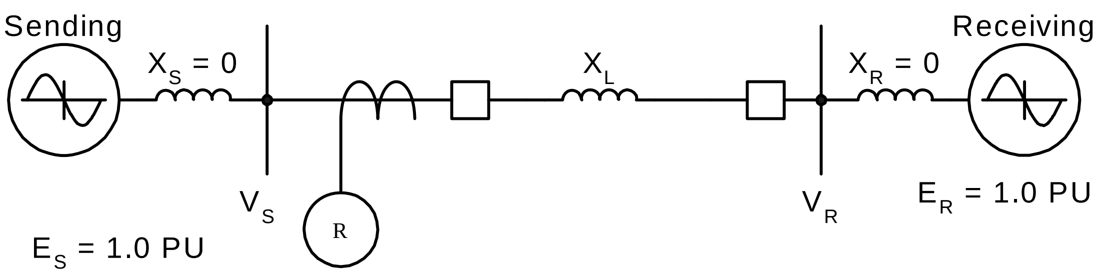



**Figure 1 – Maximum Power Transfer**

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$\delta$ = Voltage angle between $Vs$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$I_{real}$ = Real component of current

$V$ = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

$I_{total}$ is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$ (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

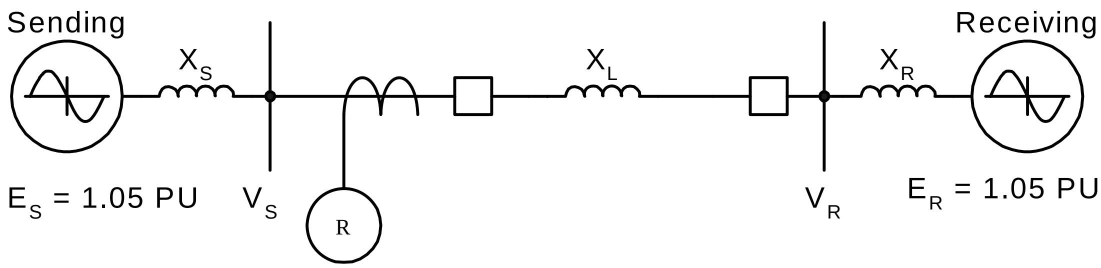



**Figure 2 – Site-Specific Maximum Power Transfer Limit**

The recommended procedure for determining $X_S$ and $X_R$ is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude ($I_{real}$) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

$V$ = Nominal phase-to-phase system voltage

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{(X_S + X_R + X_L)}}$$

Where:

$I_{total}$ = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

## R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

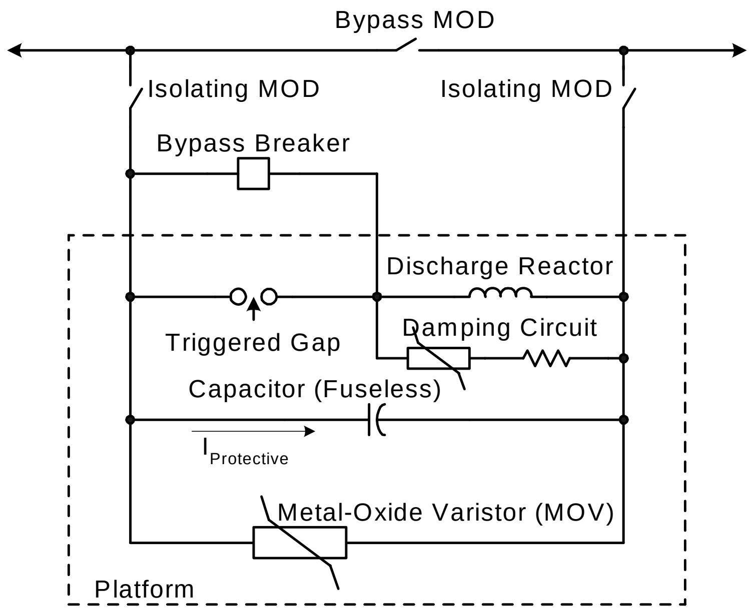



**Figure 3 – Series Capacitor Components**

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

$X_C$ = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because $I_{total}$, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. $I_{total}$ (where $I_{total}$ is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

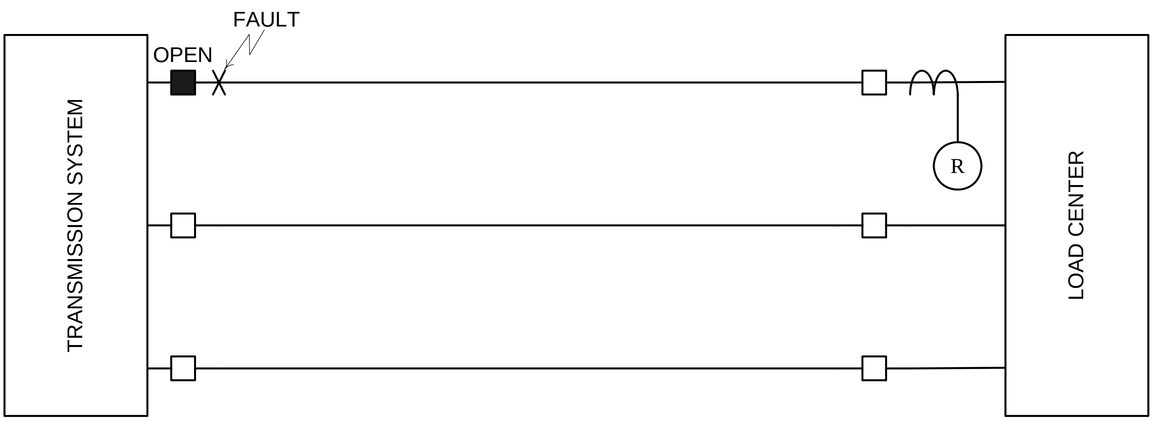



**Figure 4 – Weak Source Systems**

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{{V_S}^2 + {V_R}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$\mathrm{I_{max}} = 1.15 \times \sqrt{2} \times 1.05 \times \mathrm{I_{fault}}$$

$$\mathrm{I_{max}} = 1.70 \times \mathrm{I_{fault}}$$

Where:

$I_{fault}$ is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times $I_{fault}$, where $I_{fault}$ is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

## R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current ($I_{max}$) that the line will experience.

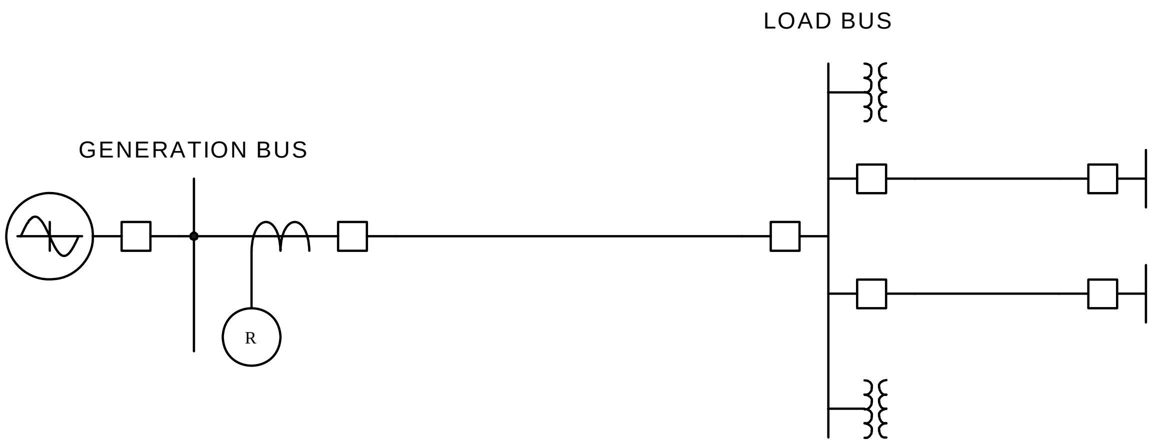



**Figure 5 – Generation Remote to Load Center**

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amps at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$\boxed{I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}}$$

Where:

$V_{relay}$ = Phase-to-phase voltage at the relay location

$N$ = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the $I_{max}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

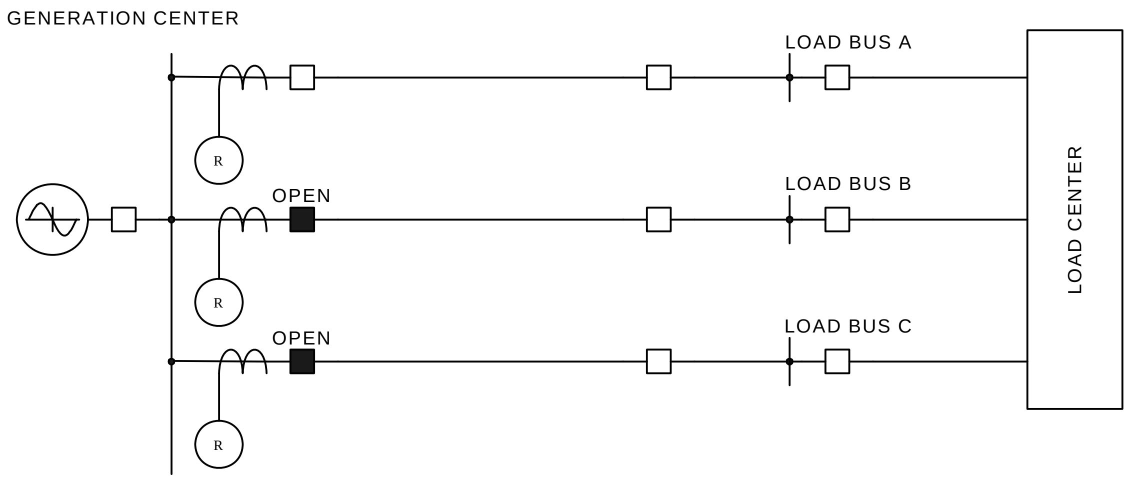



**Figure 6 – Generation Connected to System – Multiple Lines**

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The $I_{max}$ expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds $I_{max}$.

Set the tripping relay so it does not operate at or below 1.15 times $I_{max}$, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

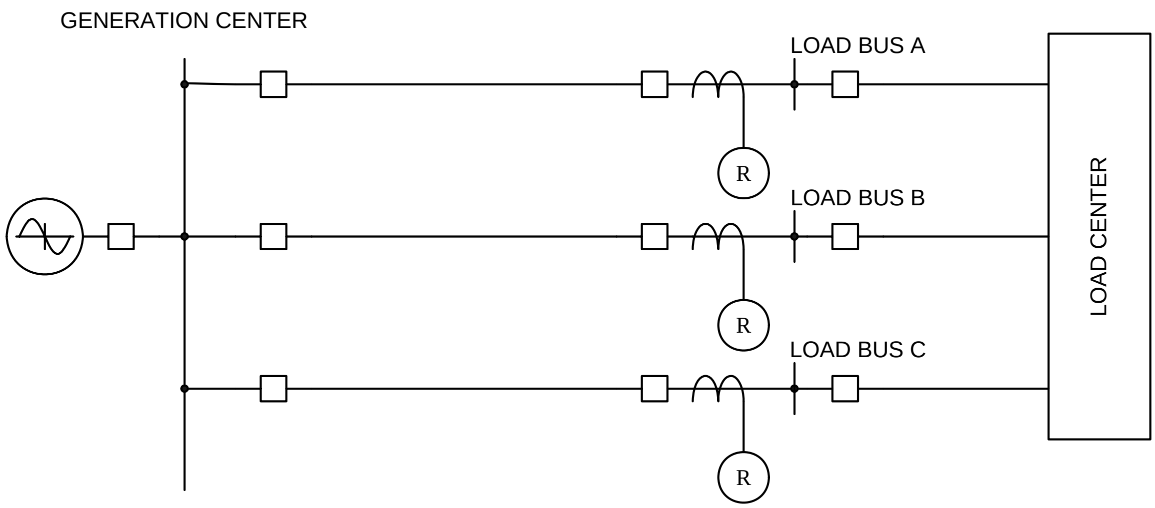



**Figure 7 – Load Remote to Generation**

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow ($I_{max}$) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

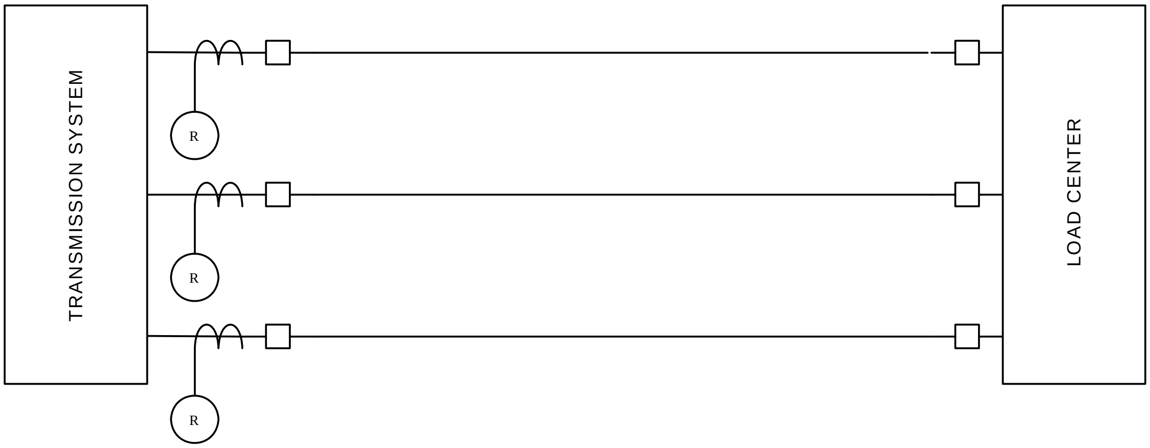



**Figure 8 – Remote Cohesive Load Center**

Also, one must determine the maximum power flow on an individual line to the area ($I_{max}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.


**Figure 9 – Cohesive Load Center Remote to Transmission System**

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow ($I_{max}$)from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

## R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer.

1. Provide the protective relay set point(s) for all load-responsive relays on the transformer.
2. Provide the reason or basis for the reduced load capability (below 150% of transformer nameplate or 115% of the operator-established emergency rating, whichever is higher) .
3. Verify that no current or subsequent planning contingency analyses identify any conditions where the recoverable flow is less than the reduced load capability (150% of transformer nameplate or 115% of the highest operator-established emergency rating, whichever is higher) and greater than the trip point.

If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100° C and 140° C[5] respectively, justification for the reduced temperature must be provided.

## R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not “overly sensitive,” and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

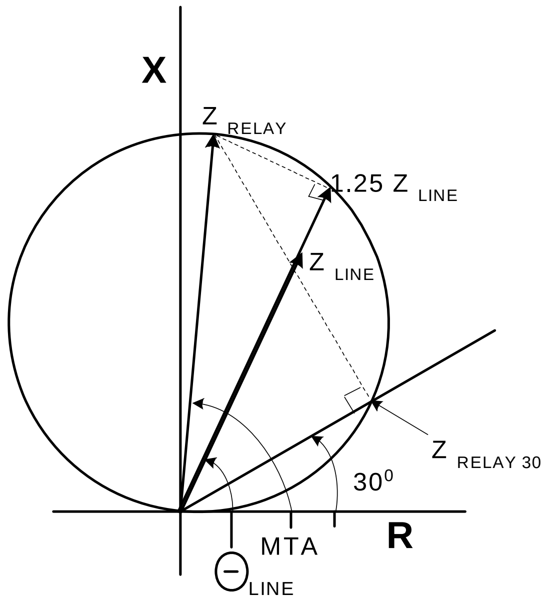



**Figure 10 – Long Line relay Loadability**

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{line}$ = Line impedance

$\Theta_{line}$ = Line impedance angle

$Z_{relay}$ = Relay setting at the maximum torque angle

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(\ MTA - \Theta_{line}\ )}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(\ MTA - 30°\ )}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left( \frac{0.341 \times V_{relay}}{Z_{line}} \right) \times \left( \frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)} \right)}$$

## R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

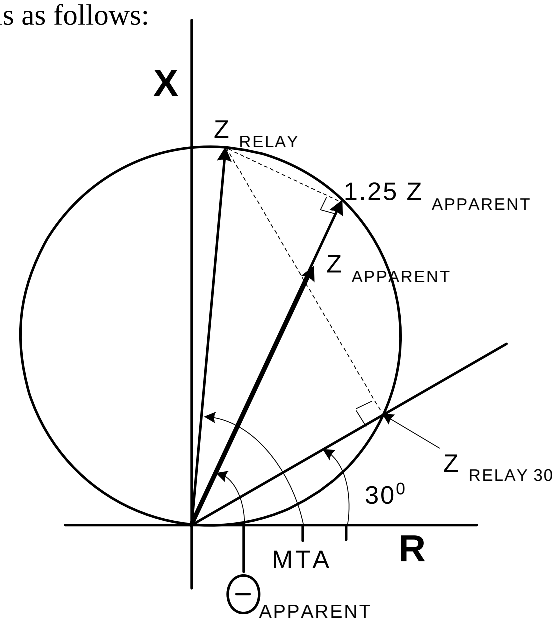



**Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps**

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed where applicable) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

$Z_{relay}$ = Relay setting at the maximum torque angle.

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

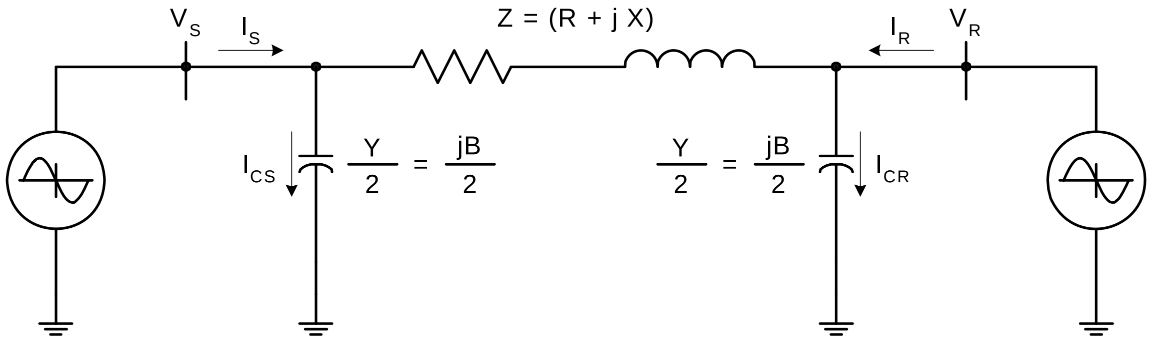
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

# Appendices

# Appendix A — Long Line Maximum Power Transfer Equations




Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\cos(\theta^\circ) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta^\circ)$$

$$Q_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\sin(\theta^\circ) - V_S^{\ 2}\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta^\circ)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos(\theta^\circ) + \sin(\theta^\circ)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta^\circ) - |Z|\frac{B}{2} - \cos(\theta^\circ)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{I_{real}^{\ 2} + I_{reactive}^{\ 2}}}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$V$ = Nominal phase-to-phase bus voltage

$\delta$ = Voltage angle between $V_S$ and $V_R$

$Z$ = Reactance, including fixed shunt reactors, of the transmission line in ohms*

$\Theta$ = Line impedance angle

$B$ = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

## Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

## *Unmodified Permissive Overreaching Transfer Trip*

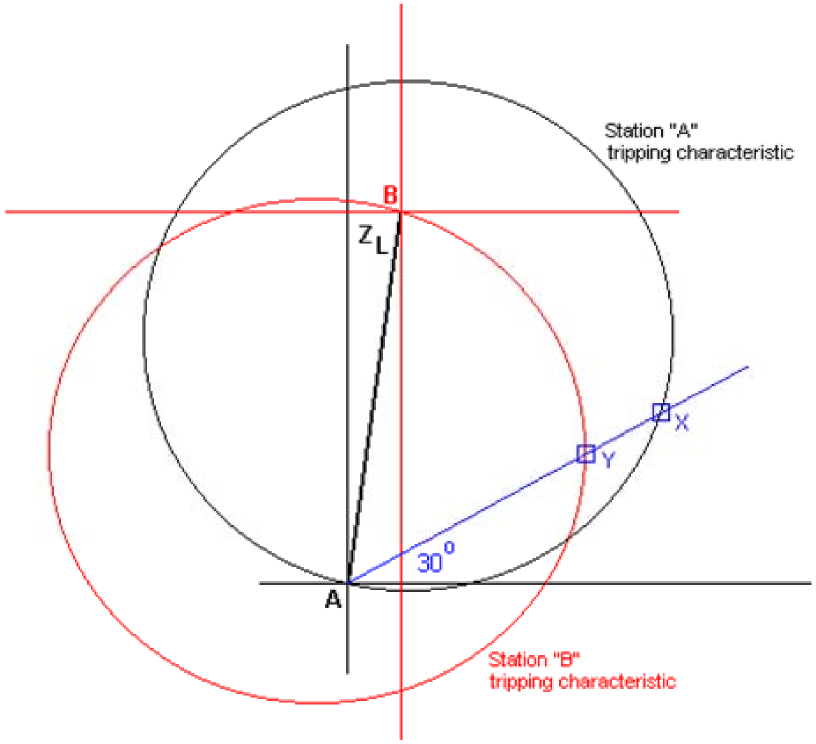



Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station "A" is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point "X" falls outside the tripping characteristic of the relay at Station "B", preventing tripping at either terminal. Relay "A" becomes susceptible to tripping along its 30-degree line only when point "Y" is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

## *Directional Comparison Blocking*

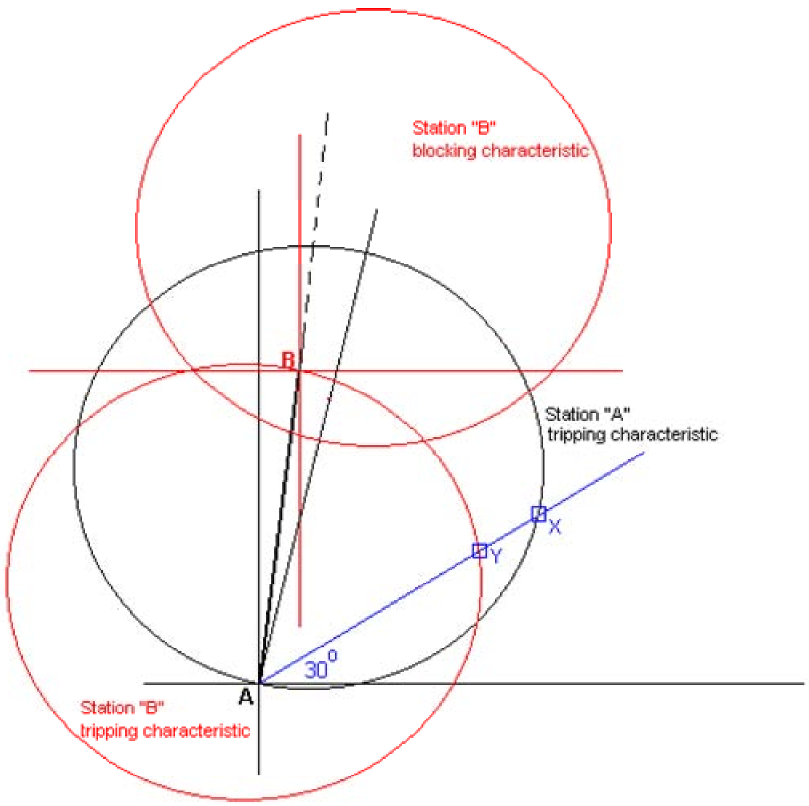



Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station “B” utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station “B” will extend into the load region of the tripping characteristic at Station “A”. The loadability of Relay “A” will therefore almost invariably be determined by the impedance AX.

## Appendix C — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, *IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13, *American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz),* 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

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NERC's System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF's Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line.

## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☐ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☐ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☐ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☐ No

   If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☐ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

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| Name: **Don Raveling** | | |
| Organization: **Montana-Dakota Utilities Co.** | | |
| Telephone: **701-222-7680** | | |
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   ☒ Yes

   ☐ No

   Comments

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   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: The reference provides additional explanations for the standard. It may be possible to comply with the standard without compliance to the reference, although I don't know how that would be done. To me this doesn't matter too much, but it perhaps would to a lawyer. What about the other reference documents on "out-of-step" and "3-terminal lines"? Would they be left as reference documents or become part of the standard too? Again they are helpful doucments and provide good and helpful informations but I think "Reference For Standard PRC-0230-1" is appropriate.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

6. Do you agree with the proposed violation risk factors?

   ☐ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   R2, 2.1, 2.2, 2.3, and M2 all require the Regional Reliability Organization (RRO), as well as the Reliability Coordinator, approve protective relay settings. This determination should be made at the Regional Reliability Organization.

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="9">☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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</table>

**Group Comments (Complete this page if comments are from a group.)**

Group Name: **WECC Reliability Coordination Comments Work Group (RCCWG)**

Lead Contact: Nancy Bellows

Contact Organization: WECC RCCWG

Contact Segment: 2

Contact Telephone: 970-461-7246

Contact E-mail: bellows@wapa.gov

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mike Gentry | SRP | WECC | 2 |
| Steve Johnson | RDRC | WECC | 2 |
| Frank McElvain | RDRC | WECC | 2 |
| Greg Tillitson | CMRC | WECC | 2 |
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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. The 2003 blackout analyses showed that relay loadability played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by “zone 3” relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

The purpose of the proposed Standard is to ensure that protection systems and settings will neither limit transmission loadability, nor contribute to cascading outages.

NERC’s System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF’s Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words “Relay Loadability Comments” in the subject line.

## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☐ Yes

   ☒ No

   Comments See Comment # 7. RCCWG does not feel that this standard accurately addresses the Industry action due to the concerns stated. That said, to the extent that extreme emergency conditions can be identified in advance of their occurrence and simulated, this standard has addressed the stated concerns.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: The RCCWG feels the standard should include all requirements. The reference document should remain a document that can be revised without requiring the standards process be followed.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference. There are, however, philosophical differences in the application of relays, even among neighbors. One example is that some entities do not utilize zone 3 relays, and others find zone 3 relaying to be a vital backup component to system protection.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

   If no, please identify which effective date should be modified and identify why.
   RCCWG feels that implementation shuold be delayed until # 7 comments are accommodated.

6. Do you agree with the proposed violation risk factors?

   ☒ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   R2, 2.1, 2.2, 2.3, and M2 all require the Regional Reliability Organization (RRO), as well as the Reliability Coordinator, approve protective relay settings. This determination should be made at the Regional Reliability Organization.

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: **Robert Rauschenbach** | | |
| Organization: **Ameren** | | |
| Telephone: **(314) 554-3535** | | |
| E-mail: **RRauschenbach@ameren.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ ECAR | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☐ | 3 — Load-serving Entities |
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| ☐ SERC | ☐ | 8 — Small Electricity End Users |
| ☐ SPP | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |
| ☐ WECC | | |
| ☐ NA — Not Applicable | | |

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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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The purpose of the proposed Standard is to ensure that protection systems and settings will neither limit transmission loadability, nor contribute to cascading outages.

NERC’s System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF’s Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words “Relay Loadability Comments” in the subject line.

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1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

☐ Yes

☒ No

Comments

A more straight forward standard should be developed where the NERC formula is used for Relay Load Limit Calculations for 230 kV and above. The Relay Load Limit would then need to be used by Operations and Planning as a line limit not to be exceeded under the NERC Table 1 conditions. The conservative 0.85 per unit voltage and 1.5 current values used in the NERC formula would provide margin against relay trips under multiple contingencies / extreme emergencies.

This method would be more performance based and less prescriptive. It avoids the exceptions and their various interpretations, and allows utilities to set relays as needed to best provide a reliable system. Requiring the Relay Load Limit to exceed the maximum thermal rating does not make sense if the thermal capacity is not being used, but merely available for ultimate designs. The requirement to exceed maximum thermal rating is what ultimately leads to the need for exceptions and their interpretation.

A utility attempting to meet this standard may be providing less backup coverage when it is not necessary. This lack of backup could ultimately lead to reduced reliability or a blackout scenario due to an un-cleared fault on the system.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

☒ Reference should be made a mandatory part of the standard

☐ Reference should be made available as a voluntary reference without mandatory compliance

Explanation for selection:

With the way the present standard is written, the reference document is necessary.

3. Are you aware of any regional differences that would be required as a result of this standard?

☒ Yes

☐ No

If yes, please identify the regional difference.

The definition of 100-200kV critical facilities is not defined and will lead to differences between regional interpretations. The requirements should be dropped for 100-200kV.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

☐ Yes

☒ No

If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why.
Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Introduction section:**

**4.1.2 Critical facilities between 100 kV and 200 kV need further definition. Each of the regions will interpret this differently. Perhaps facilities between 100 kV and 200 kV should not be included as critical until a clear definition is provided.**

**Requirements section:**

**R1.3.1 and R1.3.2 The use of 0.85 per unit voltage for relay load limit is redundant. The maximum power transfer is calculated at 1.0 per unit. The 115% factor in R1.3 already provides margin.**

**R1.5 This doesn't make sense. How can the line carry a maximum load of 1.7 multiplied by the end of line 3-phase fault? This requirement should be removed.**

**R1.6 It is not clear how the 230% factor is derived. Is this 2.0 times the generation rating time a 1.15 multiplier? For parallel lines, how many contingencies should be considered? With 4 lines in parallel, would 3 lines be assumed out-of-service? This does not appear realistic. Further definition is needed. Justification for requirements beyond those shown in NERC's Table-1 should be provided.**

**R1.8 The term 'any system configuration' is ambiguous and confusing. It is not clear how many contingencies should be considered. As is R1.6, further definition is needed, and justification for requirements beyond those shown in NERC's Table-1 should be provided.**

**R1.9 It seems R1.7 is covered under R1.9.**

**R1.12 The necessity to cover remote lines under breaker failure conditions is not addressed. Remote breaker failure coverage is required on breaker-and-a-half, ring-bus, and in-line breaker applications. The 1.25 coverage of these breaker failure conditions should be included as an exception.**

**R1.12.3 There is already margin in the relay load limit calculation. There is no need for an additional restriction on the facility rating. This is operationally burdensome and confusing to carry two load limit numbers.**

**R2 R2.1, R2.2, and R2.3 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings.**

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | **Dave Folk (on behalf of Dave Powell, Bob McFeaters, and Jim Huber)** | |
| Organization: | **FirstEnergy Corp.** | |
| Telephone: | **330-336-9063** | |
| E-mail: | **folkd@firstenergycorp.com** | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☒ ECAR | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
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   ☒ Yes

   ☐ No

   Comments

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   ☐ Reference should be made a mandatory part of the standard

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   Explanation for selection: Including the reference material with all of its technical exceptions into the standard would be confusing since the exceptions are similar to the standard's requirements but worded differently. However, attaching the non-mandatory reference material would serve as a historical record of development of the stanadard and may enhance the understanding of the standard. If future developments call for changes to the standards criteria, making the reference voluntary will allow it to remain as a background document. In addition, a citing for this reference material is needed in the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why. Both 5.1 and 5.2 should be on the same cycle. Recommend the effective date be 1/1/09 to allow time to address "lessons learned" after the 7/1/08 Beyond Zone 3 completion date. However, if staggered effective dates are used for these two requirements, they should be 6 months later than those stated to allow for incorporating "lessons learned".

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**R1 Include the words "load carrying" in front of capability.**

**R1.1 Please confirm that the 150% margin that is added on top of the 0.85 p.u. voltage and 30 degree power factor angle is not too large. Would a margin of 125-130% be sufficient? This would have a tendancy to provide an increased level of protection for the transmission system.**

**The voltage used to evaluate loadability at generating switchyard buses should not be lower than the value at which the plant auxiliary systems can be operated.**

**R1.11 This requirement is not clearly stated. Why is it referrring to R1.10? R1.10 is for fault protection relays and R1.11 is for overload relays and they say virtually the same thing. The wording in R1.11 does not reflect the intent of the reference document. The reference document section similar to R1.11 allows for lower settings with supporting documentation. Therefore reference to R1.11 should be included in M2.**

**R1.12 Include the words "load carrying" in front of capability.**

**M2 What is meant by the terms circuit rating and facility rating? Do they need special definitions.**

**General :**

**Should this standard include definitions for several special terms used in this standard?**

**Consider a bi-annual review and self-certification or data submittal rather than an annual review.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **Ed Davis** | | |
| Organization: **Entergy Services, Inc** | | |
| Telephone: **504-495-2635** | | |
| E-mail: **edavis@entergy.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☒ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
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   ☒ Yes

   ☐ No

   Comments

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   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: Due to the technical complexities of the standard, the reference document is useful for providing guidance to achieve compliance. Although the document addresses the specific requirements and could possibly be used to determine compliance, it may not be all encompassing. It should not be used as a basis for determining any non-compliance and therefore should not be part of the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

If no, please identify which effective date should be modified and identify why.

We believe that entities should be allowed a 2 year period after FERC approval of the standard to become compliant with these kinds of standards that may require significant capital investment. First, entities should not be considered non-compliant with any requirements of any standard that is not FERC approved. Second, once the standard is approved by FERC the entity should have one year to analyze his system for compliance and to budget funds to replace needed euqipment. The second year would be needed to install the equipment and ensure the proper operation of the equipment.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

Level 3 and level 4 non-compliance criteria should be swapped since level 3 is a more severe "violation" than level 4.

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| Name: | | **NERC System Protection and Control Task Force** |
| Organization: **NERC** | | |
| Telephone: | | |
| E-mail: | | **spctf@nerc.com** |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☒ NA — Not Applicable | ☐ | 1 — Transmission Owners |
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| | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name: **NERC System Protection and Control Task Force**

Lead Contact: **Jon Sykes**

Contact Organization: **Salt River Project**

Contact Segment:

Contact Telephone: **602-236-6442**

Contact E-mail: **jasykes@srpnet.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Charles Rogers | Consumers Energy | RFC | |
| Henry Miller | American Electric Power | RFC | |
| Philip Winston | Georgia Power Co | SERC | |
| Philip Tatro | National Grid USA | NPPC | |
| Tom Weidman | Consultant | N/A | |
| John Ciufo | Hydro One | NPCC | |
| Deven Bhan | WAPA | MRO | |
| William Miller | Exelon | RFC | |
| Dave Angell | Idaho Power | WECC | |
| Baj Agrawal | Arizona Public Service | WECC | |
| Mike McDonald | Ameren | SERC | |
| Joe Burdis | PJM | RFC | |
| John D Roberts | TVA | SERC | |
| Robert Cummings | NERC | N/A | |
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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

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## Please Enter All Comments in Simple Text Format.

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   ☒ Yes

   ☐ No

   Comments PRC-023 (Draft), in Appendix A, briefly mentions Switch-onto-Fault relaying and Out-of-Step Blocking and Tripping relaying, but very little else is said about these subjects, either in the Standard or in the Reference Paper. The above-referenced previous actions addressed these subjects in detail; SOTF is the subject of an informational paper by the SPCTF. We recommend that these subjects be addressed in more detail, particularly in the Reference Document.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the Standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

☒ Yes

☐ No

If no, please identify which effective date should be modified and identify why. The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the mitigation plan is followed. These previously-approved "Temporary Exceptions" will have been approved within the "NERC 8a" and/or "Beyond Zone 3" review process by the NERC System Protection and Control Task Force with the concurrence of the NERC Planning Committee.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. As reflected in the draft Standard, the VRF for R1 must apply to only R1 in its entirety, and not to each individual sub-clause of R1, in order to accurately reflect the phrase within R1, "any one of the following criteria..."

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.**

**Regarding R1 - The phrase "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle. For example, we suggest "Relay load-carrying capacity (in amperes) shall be evaluated at 0.85 per unit voltage and at a power factor angle of 30 degrees for relays sensitive to voltage and/or power factor angle, and shall be evaluated directly for overcurrent relays."**

**Regarding R1.10 - "Transformer protection relays and relays on transformer terminated lines shall be set so that they do not operate at or below the greater of:"**

**Editorial Comments - In R2 and M2, "Requirement 13" should be "R1.13". Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either "Requirement …" or R…"**

**Although we understand the reasoning behind tying Level 4 non-compliance to a reportable disturbance, it seems to be inappropriate to do so in this Standard. No requirement is established within the Standard that specifies that a non-compliance shall not contribute to a reportable disturbance. Standards set forth Requirements and Measures by which compliance with the requirements will be assessed. The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance. While I agree that causing a reportable disturbance is a significant concern, I feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance. Failure to comply with the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard. If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Compliance section of each and every Standard for which non-compliance could lead to a reportable disturbance. Establishing such penalties outside the Standards would ensure uniform treatment for all such events.**

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **CP9, Reliability Standards Working Group**

Lead Contact: **Guy V. Zito**

Contact Organization: **NPCC**

Contact Segment: **2**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

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| Bill Shemley | ISO-New England | NPCC | 2 |
| Al Adamson | New York State Rel. Council | NPCC | 2 |
| Roger Champagne | TransEnergie HydroQuebec | NPCC | 1 |
| Don Nelson | Mass. Dept of Tele. and Energy | NPCC | 9 |
| Mike Gopinathan | Northeast Utilities | NPCC | 1 |
| Ralph Rufrano | New York Power Authority | NPCC | 1 |
| Guy V. Zito | Northeast Power Coor. Council | NPCC | 2 |
| Jim Ingleson | New York ISO | NPCC | 2 |
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   ☒ Yes

   ☐ No

   Comments

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3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☒ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   **Guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | **David Kiguel - John Ciufo** | |
| Organization: | **Hydro One Networks Inc.** | |
| Telephone: | **416-345-5313** | |
| E-mail: | **David.Kiguel@HydroOne.com** | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☒ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

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   ☐ Yes

   ☒ No

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   ☒ Yes

   ☐ No

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6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Requiremenr R1: The phrase "The relay performance should be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should clearly state that the requirement applies only to RELAYS that are sensitive to voltage and/or power factor angle.**

**Requirement R1.1 remove the word "seasonal" that precedes "Facility Rating of a circuit."**

**Requirement R2 amd Measure M2 make reference to requirement R.13 It should read R1.3 instead.**

**References to requirements in the documents use the full word (e.g. Requirement 1.12 in R2.20 or the abreviation Rx.y (e.g. R1.6 in R2). We recommend consistency in the use of these references.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| Telephone: **905-855-6187** | | |
| E-mail: **ron.falsetti@ieso.ca** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
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   Comments

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3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

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   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☒ Yes

   ☒ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. Agree with the violation risk factor for R.1 but not sure about the "Lower" ranking for R.2. The RRO or RC approval processonly strengthens the standard apart from the fact that it provides a platform for communication between the RC and the transmission / generator owners who would primarily be responsible for the settings. Also, the RC or RRO would have a bigger picture of the various regions and it would be relatively easier for them to analyze the impacts of the various settings on a regional level as compared to a more localized level.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   **Level 3 incorporates the clause: "… and the relay settings were causal to a Reportable Disturbance". We feel that improper or incorrect device settings or maintenance could lead eventually to that particular device being the cause of a disturbance or a reportable event. However, this should not be the basis for the violation. Linking a compliance level to a causal effect should not be part of a standard as this would render this particular standard inconsistent with the other standards.**

   **We believe that the level orders are reversed for Level 3 and Level 4. Level 3 actually refers to "non-compliance" through the statement: "Relay settings do not comply…" whereas Level 4 is referring to "supporting evidence or documentation" through the statement: "Evidence does not exist…". From the language, it clearly seems to indicate that Level 3 is more stringent than Level 4.**

   **We feel that L 2.2.1 is incorrectly stated. In its present form, it states that "Evidence that relay settings comply with one of the criteria in R.1.1 through R1.13 exists but is incomplete or incorrect". This statement should be revised as "Evidence that relay settings comply with the criteria in R1.1 through R1.13 exists but is incomplete or incorrect for one or more of the requirements".**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | **Jim Cyrulewski** | |
| Organization: | **JDRJC Associates** | |
| Telephone: | **248-515-1109** | |
| E-mail: | **jdrjcassociates@cs.com** | |
| NERC Region | | **Registered Ballot Body Segment** |
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   ☒ Yes

   ☐ No

   Comments

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   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: Anything in the reference that should be mandatory shouled be included in the standards requriements not in an attachment.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

   If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☒ Yes

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **Mark Ringhausen** | | |
| Organization: **ODEC** | | |
| Telephone: **804-290-2194** | | |
| E-mail: **mringhausen@odec.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☒ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☒ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
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   ☒ Yes

   ☐ No

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   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☐ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

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6. Do you agree with the proposed violation risk factors?

   ☒ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria ...". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.

   Requirements section:

   Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.

   R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.

   R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion.

   R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become outaged is forseable (i.e. one line is out for maintenance and a fault occurrs on the second line), applying this scenario to more multiples becomes more and more unlikely.

   R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.

R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings.

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: **James H. Sorrels, Jr.** | | |
| Organization: **American Electric Power** | | |
| Telephone: **(614) 716-2370** | | |
| E-mail: **jhsorrels@AEP.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☒ ERCOT<br>☒ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☒ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
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   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

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   Explanation for selection: The Reference material provides example calculations of how to accomplish the requirements included in the Loadability Standard. The Reference guide may need updated from time to time to stay current as an aid without the standard needing to be updated. The reference material does not add any requirements, it only explans how to meet the requirements contained in the Loadability Standard. Therfore, Reference Document should remain a separate document, but should be clearly referenced within the Loadability Standard so that it can be found and used to meet the Loadability Standard requirements.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

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If no, please identify which effective date should be modified and identify why. The implementation plan, however, should allow for previosly approved "Temporary Exceptions" to the criteria, within the Standard, as an approved mitigation plan with regard to Compliance Monitoring. The Compliance Monitoring should not result in a finding of non-compliance as long as the "Temporary Exception" mitigation plan is being followed.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. Please note that only a VRF should be assigned to R1 since each of the sub clauses of R1 is a method for accomplishing the R1 requirement.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

Level three and four seem to be reversed. Level three is dealing with a relay that actually caused an event due to not meeting the Loadability Standard requirements, while level four deals with the documentation of a relay's compliance with the Loadability Standard. Also, if the two levels are reversed, should it matter how a relay is discovered to be in non-complance with the Loadability Standard? The new level four should read: Relay settings that do not comply with the loadability criteria in R1.

The last sentence of R1 is stated for distance relay evaluation. A method to evaluate other relays should be worked into this sentence.

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: **Neil Shockey**</td></tr>
<tr><td colspan="3">Organization: **Southern California Edison**</td></tr>
<tr><td colspan="3">Telephone: **626-302-4604**</td></tr>
<tr><td colspan="3">E-mail: **neil.shockey@sce.com**</td></tr>
<tr><td>NERC Region</td><td></td><td>**Registered Ballot Body Segment**</td></tr>
<tr><td rowspan="9">☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☒ WECC<br>☐ NA — Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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   Reference R1.10 and R1.11 Is should be clear that where the relay protection referred to does not exist, that R1.10 and R1.11 are not requiring their installation, only describing their performance should they exist.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | |
|---|---|
| Name: | **Richard G Cottrell** |
| Organization: | **Consumers Energy** |
| Telephone: | **517-7881432** |
| E-mail: | **rgcottrell@cmsenergy.com** |

| NERC Region | | **Registered Ballot Body Segment** |
|---|---|---|
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   ☒ Yes

   ☐ No

   Comments The referenced activities seem to be all included in the requirements, but nothing additional seems to be included. However, the supporting information in the documents for the previous activities seems crucial to being able to meet the requirements

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

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   Explanation for selection: It seems to be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available such that it can be easily corrected if necessary. In order to support the tie between the Standard and the Reference Document, it seems that the Reference Document should be referenced within the standard, either via a statement within R1 such as "For additional guidance on these requirements, please see "PRC-023 Reference - Determination and Application of Practical Relaying Loadability Ratings", or via a similar footnoted reference on R1.

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   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

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If no, please identify which effective date should be modified and identify why. The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the established and approved mitigation plan is followed.

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If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

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**It seems that the Level 3 and Level 4 non-compliance are reversed in their severity and priority. Also, there are errors in R2 and M2; "Requirement 13" should be "R1.13", and please use a consistent approach to referencing other requirements - "Requirement" or "R".**

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|---|---|---|
| Name: **D. Bryan Guy** | | |
| Organization: **Progress Energy Carolina, Inc.** | | |
| Telephone: **(919)-546-4107** | | |
| E-mail: **bryan.guy@pgnmail.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☒ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| | ☒ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☒ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. The 2003 blackout analyses showed that relay loadability played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by "zone 3" relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

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NERC's System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF's Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line.

## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

   PEC believes the reference document separate but referenced in the standard making it available to easily correct if necessary.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why. PEC believes that the Implementation Plan for PRC-023 should be changed. Those needing to comply will need at least two years to meet new requirements once they are finalized. One year to budget and plan, another for implementation. Therefore effective date should be two (2) years from NERC BOT approval.

6. Do you agree with the proposed violation risk factors?

☐ Yes

☒ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. The Risk Factor for R1 should be Low. The standard may be new but the engineering of zone relay settings is not. Also it is unlikely that missing a setting will result in cascading outages.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.**

**Requirements section:**

**Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.**

**R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.**

**R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion.**

**R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become outaged is forseable (i.e. one line is out for maintenance and a fault occurrs on the second line), applying this scenario to more multiples becomes more and more unlikely.**

**R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.**

**R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings.**

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | **Robert Coish** |
| Organization: | | **Manitoba Hdro** |
| Telephone: | | **204-487-5479** |
| E-mail: | | **rgcoish@hydro.mb.ca** |
| NERC Region | | **Registered Ballot Body Segment** |
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☐ Yes

☐ No

Comments This standard generally addresses the industry action listed above but Manitoba Hydrohas some significant reservations about how the standard is written as well as concerns about potential risks to reliability if this standard is implemented. (1) This standard should be more directly based on expected result or performance - that collapse should be slowed or delayed to the extent of the thermal capability of facilities. Suggest the purpose statement read - Protective relay settings shall not limit transmission loadability so that uncontrolled collapse is slowed or delayed to the extent of the thermal capability of facilities. The proposed standard should make direct reference to the additional time this standard is targetting to give the operators to respond to an emergency situation. In the current draft there is a rather indirect reference to 15 minutes. (2) The Manitoba Hydro is concerned that this standard is removing some inherent thermal overload protection from the bulk electric system. In its response to comments the SAR drafting team stated -
The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides (admittedly crude) overload protection and Manitoba Hydro believes there is increased inhent risk to the bulk electric system in the sentiment of the Sar drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? A risk analysis should be conducted before implementing this standard. (3) Manitoba Hydro believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with rgard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive. (4) The SAR designates that this standard shall also be applicable to the Regional Reliability Organization. In its response to comments the SAR drafting team stated - It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include these clarifications. -
However, there are no requirements on the RRO in this standard. Specifically, where in the standards is the RRO required to identify lines/transformers critical to the reliability of the

electric system? If it is even appropriate for the RRO to come up with the methodology, the needed requirements on the RRO should include a requirement to develop the methodology in coordination with the RC, PA and the TO. (5) In 4.1.2 and 4.1.4, the words "as designated by the Regional Reliability Organization as critical to the reliability of the electric system" are not consistent with those used in the SAR (operationally significant circuits, etc.). (6) if during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wavetraps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of sevice on time?

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: In its response to comments the Sar drafting team stated that - the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. Manitoba Hydro agrees with this approach of the SAR drafting team. The reference document should not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. Manitoba Hydro recognizes the value of the reference document as a guide and the hard work that went into preparing it.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible. However, there could be regulatory issues regarding, for example, vertical clearance issues, for the proposed overloading of lines.

5. Do you agree with the proposed effective dates?

☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why.

(1)The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RRO's are required to make this designation should be recommended by the SDT and added to the implementation plan. (2) Regarding implementation plan, one would have expected an implementation time frame of the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven months after establishment of the standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC are depending on all participants to have proceded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did?

6. Do you agree with the proposed violation risk factors?

☐ Yes

☒ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. Manitoba Hydro feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**(1) Manitoba Hydro has a concern with the 15% additional margin applied to the facility rating. This can be considered a negative margin wrt protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy. (2) Does this standard expose the TO etc. to legal risk if there is damage to the public (violating virtical clearances for example) (3) If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems (not to mention the human involvement) designed and maintained with equivalent reliability to the protection system? Also, the SCADA system my be down therefore the operator may not be able to assume the role of preventing equipment damage. (4) There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 pu voltage, and power factor angle of 30 degrees. criteria may not be appropriate for all cases.(5) If you have too prescriptive a standard you may discourage people coming up with adaptive**

**solutions. (6) This standard removes the option of using zone three relays to provide more reliable system operation**
**(a)For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. (Moving blinders in may make it impossible to detect fast moving swings)(b) On interties: It may not be possible to set relays to detect fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur. (7) This standard seems to be precluding the concept of TO's etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system. (8) R2.1 and R2.2 could be combined by adding 1.12 to the list in R2.1 and removing R2.2 (9) In M1 and M2 it should be further clarified what is meant by "evidence". (11) In R2, why would it be neccesary to get approval of the RRO and RC? If each criteria choice is valid, why is this neccesary? This is unnecessary bureaucracy. (10) Is the interpretation of R1 that the TO etc. could more that one criteria within their system? (11) In Appendix A what is meant by: 1.2.3 Protection systems intended for protection during stable power swings? (12) On page 6, R1.1.2, I in the formula for Zrelay30, should 1.5 be 1.1?**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **Brent Kingsford** | | |
| Organization: **California ISO** | | |
| Telephone: **916-608-1100** | | |
| E-mail: **bkingsford@caiso.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☒ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
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   ☐ Yes

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   ☐ Yes

   ☐ No

   If yes, please identify the regional difference.

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   If yes, please identify the conflict, being as specific as possible.

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   ☐ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

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   **R2, R2.1, R2.2, R2.3, and M2 list the Reliability Coordinators as an entity that is required to approve transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13. We disagree with the standard listing Reliability Coordinators as an entity that will approve relay settings when set according to the criteria above. We are concerned that Reliability Coordinators may not be staffed with relay engineers and obtaining approval from the Reliability Coordinators would be perceived as validation of a setting when that approval would really only be an acknowledgement of the setting criteria.**

   **Reliability Coordinator should be deleted from the requirements and measures listed above.**

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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **NERC Regional Reliability Standards Working Group (RRSWG)**

Lead Contact: **David Taylor**

Contact Organization: **North American Electric Reliability Council**

Contact Segment: **N/A**

Contact Telephone: **(609) 452-8060**

Contact E-mail: **david.taylor@nerc.net**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| H. Steven Myers | Electric Rel Council of Texas | ERCOT | 2 |
| John E. Odom, Jr | Florida Reliability Coor Council | FRCC | 2 |
| Larry E. Brusseau | Midwest Reliability Organization | MRO | 2 |
| Guy V. Zito | Northeast Power Coor Council | NPCC | 2 |
| Robert W. Millard | ReliabilityFirst Corporation | RFC | 2 |
| Patrick Huntley | SERC Reliability Corporation | SERC | 2 |
| Mak Nagle | Southwest Power Pool | SPP | 2 |
| Kenneth J. Wilson | Western Electricity Coor Council | WECC | 2 |
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   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☐ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☒ Yes

   ☐ No

If yes, please identify the conflict, being as specific as possible. R2 of this draft standard requires the TO, GO, or DP to obtain approval from the RRO and RC prior to using the criteria established in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 for each circuit terminal using the listed criteria. By establishing an obligation on the TO, GO, or DP to follow RRO and RC approved criteria, this makes PRC-023-1 a "fill-in-the-blank" standard. Section 215 of the U.S. Federal Power Act does not allow enforcement of a reliability standard upon a bulk power system owner, operator or user, including the setting of financial penalties and sanctions, to the extent a portion of the requirements exists outside the standard. However, Section 215 of the U.S. Federal Power Act does allow for a Regional Entity to establish a regional reliability standard through a NERC approved procedure to make the requirements listed in R2 enforceable. Section 215 does not grant a similar right to the RC. Accordingly, the Regional Reliability Standards Working Group (RRSWG) recommends that references to the RC in R2 and M2 of this standard be removed.

The RRSWG suggests that if the intent of the drafting team is to have a regional reliability standard developed to support the NERC standard by stating approval criteria and requirements unique to the region developing the supporting standard, that the standard be revised to show in section A.4 that it is applicable to the Regional Entity (RE), not RRO, and to clearly identify the RE requirements and measurements. If, instead, the intent of the drafting team is not to have a regional reliability standard developed, the RRSWG suggests that R2 and M2 be deleted or refined to remove the "fill-in-the-blank" characteristics. To do so, the drafting team might consider the following refinement to R2 that would remove the "fill-in-the-blank" characteristics. The refinement would be to have the TO, GO, or DP develop documentation that demonstrates its application of R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 complies with the criteria in the PRC-023 Reference Document. This refinement may require an additional requirement of the entity to simply provide its relay application documentation to the RRO and the RC for its information and use. The applicable measurement would be for the RRO to verify compliance with the PRC-023 Reference Document criteria. This refinement would also require the PRC-023 Reference Document to be incorporated as an attachment to the standard or written into the NERC standard as additional requirements.

It is not the intent of the RRSWG to be overly prescriptive here. It is only our intent to provide options to the drafting team which it might not have already considered. The RRSWG assumes the drafting team will implement the appropriate revisions to the draft standard.

5. Do you agree with the proposed effective dates?

☐ Yes

☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

☐ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name: **Bonneville Power Administration Transmission**

Lead Contact: **Lorissa Jones**

Contact Organization: **Bonneville Power Adminstration**

Contact Segment:

Contact Telephone: **360-418-8978**

Contact E-mail: **ljjones@bpa.gov**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Dean Bender | Bonneville Power Administration | WECC | 1 |
| Rita Coppernoll | BPA | WECC | 1 |
| Jon Daume | BPA | WECC | 1 |
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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. The 2003 blackout analyses showed that relay loadability played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by “zone 3” relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

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## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the “NERC Recommendation 8a Review” and the “Protection System Review Program – Beyond Zone 3”. Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an ‘Attachment’ to the standard and made mandatory **or** provided as a ‘Voluntary Reference’ outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: I don't see how you could be in compliance with one and not the other. The reference supplies necessary details and should be an attachment to the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☒ Yes

   ☐ No

   If yes, please identify the regional difference. It is more difficult to make relays on long transmission lines comply with the standard. The WECC will be impacted more because of the number of long transmission lines in that region.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why. The proposed effective date of January 1, 2008 for transmission lines operated above 200kV, etc. is appropriate, but the July 1, 2008 deadline for transmission lines operated at 100kV to 200kV and transformers with low voltage terminals connected at 100kV to 200kV as designated by the regional reliability organization is not adequate because all of the regional reliability organizations have not yet designated which lines and transformers will fall under this requirement. The proposed effective date for these lines and transformers should be at least two years after the regional reliability organization has designated the lines and transformers that are required to meet this reliability standard.

6. Do you agree with the proposed violation risk factors?

☐ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. I think that the risk factor should be high.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Comments on NERC Line Loadability Standard PRC-023 Reference**

Most WECC members are well aware of the problem of setting zone 2 or zone 3 distance relays on long transmission lines with enough reach to adequately protect the line without violating NERC recommendation 8A. The problem arises because the thermal current limit of a line is independent of the lines length and does not change for a given conductor size no matter how long it is. The impedance of the line, however, increases with the lines length. As the line length and impedance increases, the reach of the distance relays that protect the line must also increase to provide adequate protection, until at some point the relay setting would operate for the maximum thermal current. This creates the dilemma of how to protect such a long line without limiting its load carrying ability.

On the other hand, as the line length and impedance increases, the ability to transfer power across the line diminishes until a point is reached where the maximum possible power transfer is less than the rated thermal power transfer limit. Using this diminished power transfer capability instead of the thermal limit as the basis of setting the reach of the distance relays should allow for a longer relay reach that will hopefully provide adequate protection for the line.

Requirements R1.3.1 and R1.3.2 of NERC Standard PRC-023-1, and as detailed in the *PRC-023 Reference*, attempt to allow the use of the maximum power transfer capability of a line to justify the use of relay settings that will operate at loads less than the line's thermal rating. While this approach has merit, I have the following concerns:

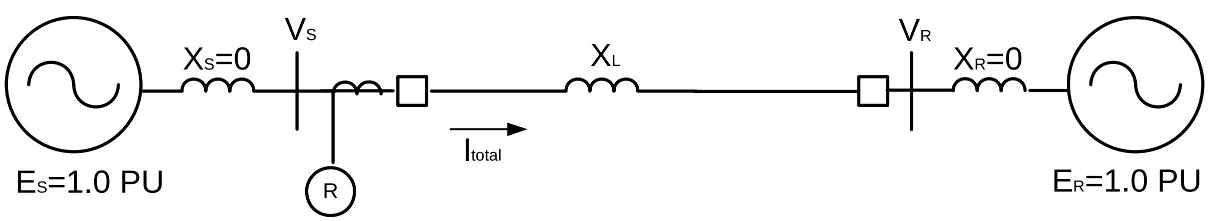
1) R1.3.1, correctly applied, will not justify a mho characteristic relay reach at the line impedance angle greater than 100% of the line impedance, and therefore, is not useful.

2) R1.3.2 offers little improvement over R1.3.1 and is not likely to justify the necessary reaches of zone 2 or 3 relays on very long lines.

3) The impedance seen by a relay is a constant percentage of the line impedance for any given power angle. This can be used to determine the maximum acceptable relay reach for any power angle. This may be useful to justify practical limits for relay reach.

Following is my explanation of the above concerns.

**1) R1.3.1 Does Not Justify Relay Reaches Greater Than 100% of the Line Impedance**




R1.3.1 attempts to determine a relay reach based on the maximum theoretical power flow across a line that occurs when the power angle, δ, is 90°.

From R1.3.1 of the *PRC-023 Reference*, page 4:

$I_{total} = (V_{LL}\sqrt{2})/(X_L\sqrt{3})$

The impedance seen by the relay is:

$Z_R = V_{LG}/I_{total}$   where $V_{LG}$ is the line-to-ground voltage and $V_{LG} = V_{LL}/\sqrt{3}$ under balanced load

$Z_R = (V_{LL}/\sqrt{3}) / [(V_{LL}\sqrt{2})/(X_L\sqrt{3})]$

$Z_R = X_L/\sqrt{2}$

So the impedance seen by the relay, $Z_R$, is independent of the bus voltage during a maximum power transfer condition. If the voltage sags, the maximum possible power transfer across the line will also drop, and the impedance seen by the relay will remain constant.

Under the conditions assumed in R1.3.1, $|V_S| = |V_R|$ and the angle between $V_S$ and $V_R$ (power angle, δ) is 90°, the current through the line, $I_{total}$ will lag the voltage at the sending end by 45°, and the impedance seen by the relay, $Z_R$ , will be at 45°. Converting this to the maximum allowable reach for a mho characteristic relay at the line angle of 90° gives:

$Z_{90} = Z_R / \cos(90°-45°) = (X_L/\sqrt{2}) / \cos 45° = X_L$

The result shows that for a mho characteristic distance relay, the maximum power transfer approach will never justify setting the reach of a mho characteristic beyond 100% of the line impedance. Stated another way, at the maximum theoretical power transfer, a mho-characteristic distance relay with a reach equal to 100% of the line impedance at a maximum torque angle of 90° will pick up on load.

The results derived in R1.3.1 are slightly different because two safety factors are introduced. The first a voltage factor of 0.85 isn't necessary because, as shown above, the impedance seen by the relay is unaffected by the voltage when the maximum power transfer approach is used. The second safety factor increases the current by 1.15 which results in a reduced allowable relay reach of 1/1.15 or 87%.

Even with the safety factors, the impedance allowed by R1.3.1 is still larger than the value derived above ($Z_{90} = X_L$) because R1.3.1 incorrectly recommends that the impedance derived from the maximum power transfer equation be applied at a power factor angle of 30° instead of 45°. From R1.3.1:

$Z_{relay30} = (0.85V_{LL}) / (1.15 \cdot I_{total}\sqrt{3}) = (0.85/1.15)(V_{LL} \cdot X_L\sqrt{3})/(V_{LL}\sqrt{2}\sqrt{3})$

$Z_{relay30} = (0.85/1.15)(X_L /\sqrt{2}) = 0.739X_L/\sqrt{2}$

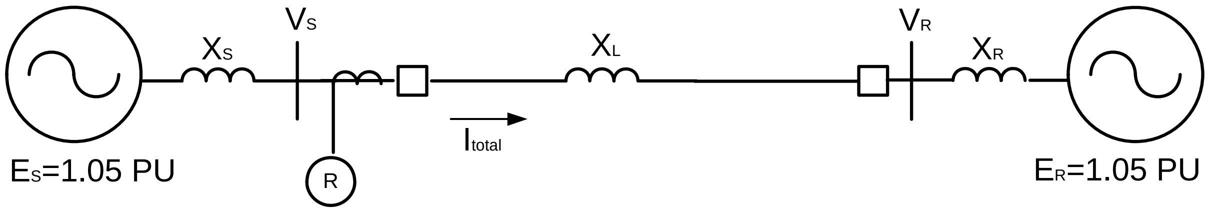
The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°-30°) = (0.739X_L/\sqrt{2}) / \cos 60°$

$Z_{90} = 1.045 \cdot X_L$

So, the use of a 30° power factor angle as recommended in R1.3.1 offsets the safety margins that were applied and allows a slightly longer distance relay reach of 104.5% of the line impedance. This is not enough reach for a zone 2 relay to provide adequate protection for the line. The maximum power transfer approach, as used in R1.3.1, is useless in justifying adequate zone 2 settings for long lines!

**2) R1.3.2 Offers Little Help Over R1.3.1**




R1.3.2 uses the source impedances of the system to obtain a reduced maximum theoretical power flow at the power angle, δ, of 90°, and therefore a longer allowable relay reach than obtained by R1.3.1

From R1.3.2 of the *PRC-023 Reference*, page 6:

$I_{total} = (1.05V_{LL}\sqrt{2}) / [(X_S + X_R + X_L)\sqrt{3}]$

$Z_{relay30} = (0.85V_{LL}) / (1.15 \cdot I_{total}\sqrt{3}) = (1/1.05)(0.85/1.15)(X_S + X_R + X_L)/\sqrt{2} = 0.498(X_S + X_R + X_L)$

This is the same impedance seen by the relay as derived in R1.3.1 with $X_L$ replaced by $(X_S + X_R + X_L)$ and the result divided by 1.05 because of the 1.05 P.U. source voltage used.

The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°\text{-}30°) = 0.498(X_S + X_R + X_L) / \cos 60°$

$Z_{90} = 0.996(X_S + X_R + X_L)$

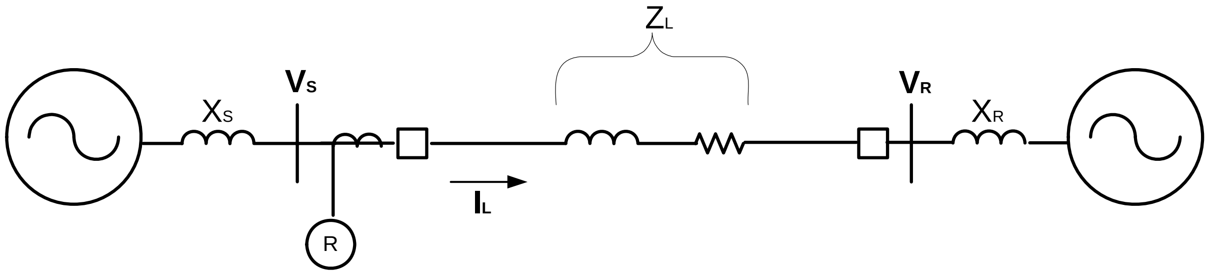
This shows that the maximum allowable reach of a mho characteristic relay at the line angle is approximately equal to $(X_S + X_R + X_L)$. This method will only allow a mho characteristic relay to overreach the line impedance by the same percentage that $X_s + X_R$ is to the line impedance $X_L$.

$Z_{90} = 0.996 \cdot X_L\ [1+ (X_R + X_S)/X_L]$

In order to justify setting a zone 2 relay at the standard 125% of the line impedance with this method, $X_S + X_R$ must equal 25% of $X_L$. For many long lines the source impedance at the terminals will not equal 25% of the line impedance and this method will not justify a mho characteristic reach that provides adequate line protection.

As in R1.3.1, R1.3.2 applies the relay reach at a power factor angle of 30° instead of the correct angle of 45°. Using 45° results in even less allowable relay reach.

### 3) Another Approach




From the above diagram where $\mathbf{V_S}$ is the phase-to-ground voltage at the sending end, and $\mathbf{V_R}$ is the phase-to-ground voltage at the receiving end:

$\mathbf{V_S} = V_S\angle\Theta_S$ and $\mathbf{V_R} = V_R\angle\Theta_R$

$\mathbf{I_L} = (V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L$

The impedance seen by the relay, $Z_R$, is:

$Z_R = \mathbf{V_S} / \mathbf{I_L} = V_S\angle\Theta_S / [(V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L]$

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S - V_R\angle\Theta_R)$

If the receiving end voltage is used as the reference, $\Theta_R = 0°$ and the power angle $\delta = \Theta_S - \Theta_R = \Theta_S$. If the magnitude of the sending- and receiving-end voltages are equal, $V_R = V_S$, and we get:

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S - V_S\angle 0°)$

$Z_R = Z_L \cdot V_S\angle(\Theta_S+\Theta_L) / V_S(1\angle\Theta_S - 1)$

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) / (1\angle\Theta_S - 1)$

This shows that the impedance seen by the relay, $Z_R$, is dependent only on the difference in angles between the sending and receiving end voltages and the magnitude and angle of the line impedance. The following table shows some values of $Z_R$ for different values of $\Theta_S$ when the line impedance angle, $\Theta_L$ , is 90°. The far right column shows the corresponding relay reach at 90° for a mho characteristic distance relay ($Z_{R90} = Z_R/\cos[90° - \Theta_{ZR}]$).

| $\Theta_S$ | $Z_R$ | Relay reach at line angle of 90° |
|---|---|---|
| 90° | $(0.707\angle 45°)\cdot Z_L$ | $1.0\cdot Z_L$ |
| 85° | $(0.740\angle 42.5°)\cdot Z_L$ | $1.095\cdot Z_L$ |
| 80° | $(0.778\angle 40°)\cdot Z_L$ | $1.210\cdot Z_L$ |
| 75° | $(0.821\angle 37.5°)\cdot Z_L$ | $1.349\cdot Z_L$ |
| 70° | $(0.872\angle 35°)\cdot Z_L$ | $1.520\cdot Z_L$ |
| 65° | $(0.931\angle 32.5°)\cdot Z_L$ | $1.732\cdot Z_L$ |
| 60° | $(1.00\angle 30°)\cdot Z_L$ | $2.00\cdot Z_L$ |

The table shows that in order to get a useful zone 2 reach of 125% or more of the line impedance, the power angle must be less than about 78°.

If the line impedance angle, $\Theta_L$ , is different than 90°, the allowable relay reach at the line angle will still be the same as that shown for a line angle of 90° in the table above. For example, the allowable relay reach for a line impedance angle of 80° on a system operating at a power angle of 75° gives:

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) \,/\, (1\angle\Theta_S - 1)$

$Z_R = Z_L \cdot 1\angle(75°+80°) \,/\, (1\angle 75° - 1)$

$Z_R = Z_L \cdot (0.821\angle 27.5°)$

The allowable relay reach at the line angle of 80° is:

$Z_{R80} = Z_L \cdot 0.821 \,/\, \cos(80°-27.5°)$

$Z_{R80} = 1.349 \cdot Z_L$

This is the same reach as the one in the table above for a power angle of 75°. This example can be applied to any line and power angle, and the above table can be generalized to:

| Power Angle δ | Mho Characteristic Relay Reach at Line Angle |
|---|---|
| 90° | $1.0 \cdot Z_L$ |
| 85° | $1.095 \cdot Z_L$ |
| 80° | $1.210 \cdot Z_L$ |
| 75° | $1.349 \cdot Z_L$ |
| 70° | $1.520 \cdot Z_L$ |
| 65° | $1.732 \cdot Z_L$ |
| 60° | $2.00 \cdot Z_L$ |

If we wanted to set a mho characteristic relay to reach 130% of the line impedance at the line angle ($Z_{LA}$) and allowed for a 15% overreach error, we'd have

$Z_{LA} = (1.15)(1.30)\, Z_L = 1.495 \cdot Z_L$

From the above table, the relay would not pick up on load until the power angle across the line exceeded 70°.

**Summary**

Trying to justify zone 2 and zone 3 relay reaches on long lines using the maximum power transfer capability of the line as described in R1.3.1 doesn't work. The method described in R1.3.2 will be very limited in its usefulness. A more useful approach would be to select a practical power angle less than 90° that is not exceeded during stable power system operation and base the maximum relay reach on that. Can a power angle of less than 90° be accepted as a practical limit that is unlikely to be exceeded in real-life operation? If so, a maximum relay reach, as a percentage of line impedance at the line angle, should be allowed for mho characteristic relays without further restrictions or justification. For example, if a 70° power angle is acceptable as a limit that is unlikely to be exceeded in stable operation, a relay reach at the line angle of 130% of the line impedance could be allowed without further restriction or justification. This could greatly reduce the number of relay settings requiring an exception to the standard.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | **Herb Schrayshuen** | |
| Organization: | **National Grid** | |
| Telephone: | **(315) 428-3159** | |
| E-mail: | **herbert.schrayshuen@us.ngrid.com** | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☒ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: The entire Reference Document should not be incorporated in the Standard, however, the Standard Drafting Team should review the draft Standard to ensure that adequate information is contained in each Requirement to ensure consistent interpretation and application. In some cases important information necessary to apply the stated Requirement is contained in text or a diagram within the Reference Standard. Some examples that we find requiring further clarification include:

   R1.3: Additional information is required regarding line resistance and the power angle between the sending and receiving line terminals.

   R1.3.2: The reference to 1.05 p.u. voltage should identify this as the Thevenin equivalent source voltage behind the actual system source impedance at each end of the line, rather than at the end of the line.

   R1.12: The maximum distance relay setting should clarify that the reach at the maximum torqure angle (MTA) shall be set to provide no greater than 125% overreach at the impedance angle of the protected transmission line. The present language could be interpreted as requiring a setting of no more 125% of the line impedance magnitude applied at the MTA, which may not provide adequate protection coverage at the line impedance angle.

   The Reference Document contains a significant volume of information to assist the industry in applying the Standard. Additional information as noted above should be included in the Standard, and the remaining information in the Reference document should be posted with the Standard on the NERC website as a separate reference source.

3. Are you aware of any regional differences that would be required as a result of this standard?

☐ Yes

☒ No

If yes, please identify the regional difference.

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☐ Yes

☒ No

If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

☒ Yes

☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Section B -- Requirements**

**R1: The Standard should clarify that the protection system owner is free to select any of the criteria in R1.1 through R1.13 and need not apply the same one on all protection systems.**

**R11: The Standard should allow for overcurrent settings set below 150% of the maximum transformer nameplate rating or 115% of the highest operator established emergency transformer rating if the relays are supervised by a distance element that meets the relay loadability requirements.**

**R2: The reference to "R.13" should be "R1.13". The same error is repeated under Section C - Measures at M2 and under Section D - Compliance at 2.1.1.**

**R2.1 and R2.2: Given the identical wording in these two requirements it is not clear to the reader why these two requirements could not be combined. Additional text should be added to clarify that R2.1 pertains to criteria used to verify that the loading cannot be reasonably expected to exceed relay loadability, whereas R2.2 pertains to a criterion that establishes an equipment rating less than its actual capability based on the relay setting.**

**Section D -- Compliance**

**We do not agree with assigning different Levels of Non-Compliance depending on the method by which the non-compliance is identified.  The draft Standard sets forth the Requirements and the Measures by which compliance with the requirements will be assessed.  The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance.  While we agree that causing a reportable disturbance is a significant concern, we feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance.  Failure to comply with a Requirement in the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard.  If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Standards.  Establishing such penalties outside the Standards would ensure uniform treatment for all such events.**

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: **Tim Bartel** | | |
| Organization: **Minnkota Power Cooperative, Inc.** | | |
| Telephone: **701-795-4314** | | |
| E-mail: **tbartel@minnkota.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ ECAR | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| ☐ FRCC | ☒ | 3 — Load-serving Entities |
| ☐ MAAC | ☐ | 4 — Transmission-dependent Utilities |
| ☐ MAIN | ☒ | 5 — Electric Generators |
| ☐ MRO | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ NPCC | ☐ | 7 — Large Electricity End Users |
| ☐ SERC | ☐ | 8 — Small Electricity End Users |
| ☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☐ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☐ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☐ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

☐ No

If no, please identify which effective date should be modified and identify why.

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☐ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

Using this one-size-fits-all approach for out-of-step blocking / tripping relays would prevent proper application in some situations. Orderly system separation following major events may require higher impedance out-of-step blinder settings than would be allowed by the standard.

Perhaps this is allowed for by the reference to "stable power swings" in section 1.2.3 of Attachement A, but it is not clear if this is the case.

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| Telephone: | | |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **Midwest Reliability Organization**

Lead Contact: **Robert Coish**

Contact Organization: **Midwest Reliability Organization**

Contact Segment: **2**

Contact Telephone: **(204) 487-5479**

Contact E-mail: **rgcoish@hydro.mb.ca**

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| Terry Bilke | MISO | MRO | 2 |
| Ken Goldsmith | ALT | MRO | 2 |
| Carol Gerou | MP | MRO | 2 |
| Todd Gosnell | OPPD | MRO | 2 |
| Wayne Guttormson | SPC | MRO | 2 |
| Jim Maenner | WPS | MRO | 2 |
| Tom Mielnik | MEC | MRO | 2 |
| Darrick Moe Chair | WAPA | MRO | 2 |
| Pam Oreschnick | XEL | MRO | 2 |
| Dick Pursley | GRE | MRO | 2 |
| Dave Rudolph | BEPC | MRO | 2 |
| Eric Ruskamp | LES | MRO | 2 |
| Joe Knight, Secretary | MRO | MRO | 2 |
| | | MRO | 2 |
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1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

☐ Yes

☐ No

Comments The MRO generally believes this standard addresses the industry action listed above but has some significant reservations about how the standard is written as well as concerns about potential risks to reliability if this standard is implemented. (1) This standard should be more directly based on the concept that collapse should be slowed or delayed to the extent of the thermal capability of facilities. Suggest the purpose statement read - Protective relay settings shall not limit transmission loadability uncontrlled collapse is slowed or delayed to the extent of the thermal capability of facilities. The proposed standard should make direct reference to the additional time this standard is targetting to give the operators to respond to an emergency situation. In the current draft there is a rather indirect reference to 15 minutes. (2) The MRO is concerned that this standard is removing some inherent thermal overload protection from the bulk electric system. In its response to comments the SAR drafting team stated - The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides (admittedly crude) overload protection and MRO believes there is increased inhent risk to the bulk electric system in the sentiment of the Sar drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? The MRO believes that a risk analysis should be conducted before implementing this standard. (3) The MRO believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with rgard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive. (4) The SAR designates that this standard shall also be applicable to the Regional Reliability Organization. In its response to comments the SAR drafting team stated - It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include these clarifications. - However, there are no requirements on the RRO in this standard. Specifically, where in the standards is the RRO required to identify lines/transformers critical to the reliability of the electric system? If it is even appropriate for the RRO to come up with the methodology, the needed requirements on the RRO should include a requirement to develop the methodology in coordination with the RC, PA and the TO. (5) In 4.1.2 and 4.1.4, the words "as designated by the Regional Reliability Organization as critical to the reliability of the electric system" are not consistent with those used in the SAR (operationally significant circuits, etc.). (6) if during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wavetraps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of sevice on time?

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an ‘Attachment’ to the standard and made mandatory **or** provided as a ‘Voluntary Reference’ outside the standard to support implementing the standard? Explain why.

☐ Reference should be made a mandatory part of the standard

☒ Reference should be made available as a voluntary reference without mandatory compliance

Explanation for selection:

(1)In its response to comments the Sar drafting team stated that

- the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. The MRO agrees with this approach of the SAR drafting team. The reference document should not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. The MRO recognizes the value of the reference document as a guide and the hard work that went into preparing it. (2) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states generator protection relays are excluded from requirements of this PRC-023-1 standard(Page 1,section 2.3,reference document). The attachment A (section 1.2.4) to standard PRC-023-1 states generator protection relays that are susceptible to load are excluded from requirements of this PRC-023-1 standard. Should the attachment A of the standard be consistent with the reference document for the standard? (3) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 9 states 200% of aggregated generation nameplate capability when the standard lists 230% of aggregated generated nameplate capability. (section R1.6) Why is the standard 230% when its reference document uses 200%? (4) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 14 “If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100°C and 140 C respectively, justification for the reduced temperature must be provided.” Where as in the standard (section R.11, last part), the standard states “Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100 C for the top oil or 140°C for the winding hot stop temperature.”

Shouldn't the reference document be consistent with the standard? (Where anything less than 100°C and 140 C would have justification associated with it.)

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible. However, there could be regulatory issues regarding, for example, vertical clearance issues, for the proposed overloading of lines.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

   If no, please identify which effective date should be modified and identify why.

(1)The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RRO's are required to make this designation should be recommended by the SDT and added to the implementation plan. (2) Regarding implementation plan, one would have expected an implementation time frame of the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven months after establishment of the standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC are depending on all participants to have proceeded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did?

6. Do you agree with the proposed violation risk factors?

   ☐ Yes

   ☒ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. TThe MRO feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**(1) The MRO has a concern with the 15% additional margin applied to the facility rating. This can be considered a negative margin wrt protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy. (2) Does this standard expose the TO etc. to legal risk if there is damage to the public (violating virtical clearances for example) (3) If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems (not to mention the human involvement) designed and maintained with equivalent reliability to the protection system? Also, the SCADA system my be down therefore the operator may not be able to assume the role of preventing equipment damage. (4) There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 pu voltage, and power factor angle of 30 degrees. criteria may not be appropriate for all cases.(5) If you have too prescriptive a standard you may discourage people coming up with adaptive solutions. (6) This standard removes the option of using zone three relays to provide more reliable system operation (a) For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. (Moving blinders in may make it impossible to detect fast moving swings)(b) On interties: It may not be possible to set relays to detect fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur. (7) This standard seems to be precluding the concept of TO's etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system. (8) R2.1 and R2.2 could be combined by adding 1.12 to the list in R2.1 and removing R2.2 (9) In M1 and M2 it should be further clarified what is meant by "evidence". (11) In R2, why would it be neccesary to get approval of the RRO and RC? If each criteria choice is valid, why is this neccesary? This is unnecessary bureaucracy. (10) Is the interpretation of R1 that the TO etc. could more that one criteria within their system? (11) In Appendix A what is meant by: 1.2.3 Protection systems intended for protection during stable power swings?**

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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **ISO / RTO Council**

Lead Contact: Charles Yeung

Contact Organization: SPP

Contact Segment: 2

Contact Telephone: (832) 724 - 6142

Contact E-mail: cyeung@spp.org

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Thomas Bowe | PJM | RFC | 2 |
| Peter Brandien | ISO - NE | NPCC | 2 |
| Michael Calimano | NYISO | NPCC | 2 |
| John Dumas | ERCOT | ERCOT | 2 |
| Ron Falsetti | IESO | NPCC | 2 |
| Brent Kingsford | CAISO | WECC | 2 |
| Anita Lee | AESO | WECC | 2 |
| Bill Phillips | MISO | RFC | 2 |
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   ☒ Yes

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   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: The IRC supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents. Unless the material in the Technical Requirement is required, then the Reference Document should be kept separate from the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

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If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

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**The IRC favors standards that define performance requirements and measure compliance based on that performance. The IRC questions the incorporation of difference Levels of Compliance based on the cause of the given performance.**

**NERC already has a process that includes Violation Risk Factors and Violation Severity Levels to 'adjust' non-compliance penalities. To include another subjective adjustment factor would seem to be inappropriate.**

**The IRC suggests that the SDT consider reversing the level orders for Level 3 and Level 4. From the language in the standard, the current Level 3 is more stringent than Level 4.**

**The IRC does not agree that the Reliability Coordinators should be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The IRC notes that not all RCs have appropriate expertise in making such determinations and therefore suggests that the verification of relay settings is more appropriate at the Transmission Operator level. Further the Functional Model White Paper does not include any relay setting or authorization responsibilities for the RC.**

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<table>
<tr><th colspan="3">Individual Commenter Information<br>(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Makarand Nagle</td></tr>
<tr><td colspan="3">Organization: Southwest Power Pool</td></tr>
<tr><td colspan="3">Telephone: 501-614-3564</td></tr>
<tr><td colspan="3">E-mail: mnagle@spp.org</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
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<tr><td>☐</td><td>6 — Electricity Brokers, Aggregators, and Marketers</td></tr>
<tr><td>☐</td><td>7 — Large Electricity End Users</td></tr>
<tr><td>☐</td><td>8 — Small Electricity End Users</td></tr>
<tr><td>☐</td><td>9 — Federal, State, Provincial Regulatory, or other Government Entities</td></tr>
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</table>

**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the “NERC Recommendation 8a Review” and the “Protection System Review Program – Beyond Zone 3”. Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☐ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an ‘Attachment’ to the standard and made mandatory **or** provided as a ‘Voluntary Reference’ outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☐ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☐ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☐ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☐ No

   If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

☐ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**NERC should provide, as a part of the standard, the loadability verification spreadsheet(s) and technical exceptions documentation it wants for documentation purposes. There may be many differing opinions on what documentation is acceptable. However, NERC should have created forms/spreadsheets/papers for completion that satisfy their documentation for loadability requirements.**

**Although SPP agrees with the need for a protection loadability standard, we believe this standard should apply to only 345kV and above systems. Most companies with 345kV and above have a larger impact on wide area/multi-state blackouts. Although the 100 to 200 kV systems may be critical to a localized region, loss of those voltages will probably not spread into a multi-state blackout, provided the 345kV and above systems remain in service. There are other regional requirements for loading and line ratings that probably suffice for the localized regions.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
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| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name: **FRCC**

Lead Contact: **Eric Senkowicz**

Contact Organization: **FRCC**

Contact Segment: **2**

Contact Telephone: **813-289-5644**

Contact E-mail: **esenkowicz@frcc.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☐ No

   Comments

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   Explanation for selection: The reference document should be made "voluntary" in order to preserve and maintain the clarity of the requirements within the standard. The current compliance programs are not designed to interpret and measure reference documents and therefore would make compliance enforcement to another "type" of document inappropriate, difficult and confusing, especially with regard to the technical nature of the content.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

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   ☐ Yes

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☒ Yes

☐ No

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☐ Yes

☒ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

R1 should be a "medium" risk factor because of the inherent potential of mis-applied settings affecting BES system performance. However, an incorrect relay setting or a mis-applied relay settting, by itself, is unlikely to lead to the effects on the BES as described in the definition of a "high" risk factor. For the setting to affect the BES to the degree as described in the definition of "high" risk factor, multiple other core operational requirements would have had to have been violated. Therefore, for a mis-applied setting to affect the overall reliable response of a system to a particular disturbance, the effects on the system would be a result of multiple requirement violations, including the lack of appropriate monitoring and analysis along with inadequate operator intervention at posturing an affected system,.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Section 2.3 and 2.4 should be swapped with regards to Levels of Non-Compliance. A mis-applied setting that was causal to a Reportable Disturbance appears to be the worst-case infraction and therefore should be the "Level 4" Non-compliance.**

**Has the drafting team considered the concept of "temporary exceptions" to the setting criteria ? One of the concerns expressed in our Region is that during certain system modifications, (ie. new lines, configuration changes, ampacity upgrades, etc) it may be necessary to deviate from the prescribed criteria on a temporary basis, so that the necessary relaying modifications may be made to accommodate the system changes? This type of "temporary exception" would allow construction implementation without racking up a violation, and still maintaining adequate equipment protection.**

**Lastly, has the drafting team considered adding a "grace" period for resolving self-identified non-compliances to the setting requirements of this standard? As an example a "non-compliant" setting that is self-identified would be reportable but would not result in a non-compliance violation if the settings were corrected within a certain time period.**

**We appreciate the team's rigorous efforts at creating this complex standard and also appreciate the opportunity to provide the above comments.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **Anita Lee** | | |
| Organization: **Alberta Electric System Operator** | | |
| Telephone: **403- 539-2497** | | |
| E-mail: **anita.lee@aeso.ca** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☒ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

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   ☒ Yes

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   Explanation for selection: The AESO supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents. Unless the material in the Technical Requirement is required, then the Reference Document should be kept separate from the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

If no, please identify which effective date should be modified and identify why. The effective date for the circuits described in 4.1.2 and 4.1.4 (transmission lines and transformers with low votage terminal at 100 kV to 200 kV) should be a certain time period after the determination by the Regional Reliability Organization of such circuits, rather than the proposed fixed effective date of July 1, 2008. This will address the concern that some RROs may be late in making those determinations. It is also not clear as to where is the requirement for the RROs to make such determination and how often a review should be made

6. Do you agree with the proposed violation risk factors?

☐ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**The AESO favors standards that define performance requirements and measure compliance based on that performance. The AESO questions the incorporation of difference Levels of Compliance based on the cause of the given performance.**

**NERC already has a process that includes Violation Risk Factors and Violation Severity Levels to 'adjust' non-compliance penalities. To include another subjective adjustment factor would seem to be inappropriate.**

**The AESO suggests that the SDT consider reversing the level orders for Level 3 and Level 4. From the language in the standard, the current Level 3 is more stringent than Level 4.**

**The AESO does not agree that the Reliability Coordinators should be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The IRC notes that not all RCs have appropriate expertise in making such determinations and therefore suggests that the verification of relay settings is more appropriate at the Transmission Operator level. Further the Functional Model White Paper does not include any relay setting or authorization responsibilities for the RC.**

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|---|---|---|
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| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **Southern Company - Transmission**

Lead Contact: **Jim Busbin**

Contact Organization: **Southern Company Services**

Contact Segment: **1**

Contact Telephone: **205-257-6357**

Contact E-mail: **jybusbin@southernco.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Marc Butts | Southern Company Services | SERC | 1 |
| J T Wood | Southern Company Services | SERC | 1 |
| Roman Carter | Southern Company Services | SERC | 1 |
| Phil Winston | Georgia Power Company | SERC | 3 |
| Terry Crawley | Southern Nuclear | SERC | 5 |
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   Explanation for selection: Southern Company Transmission agrees with the explanation for this selection made by the SERC Protection and Control Subcommittee and the NERC System Protection and Control Task Force. Their explanations state, "It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website."

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

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5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

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   ☒ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   **Southern Company Transmission supports the following portion of the comments made by the NERC System Protection and Control Task Force:**

   **"Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than 'no evidence exists to support that relays comply with one of the criteria . . . .' The existing Level 3 should also be 'causal or contributory' instead of just 'causal'. It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay), whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by 'Evidence indicates that relay settings do not comply with R1.1 through R1.13' as a Level 4 non-compliance.**

   **Regarding R1 - The phrase 'The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees' should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle.**

   **Editorial Comments - In R2 and M2, 'Requirement 13' should be 'R1.13'. Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either 'Requirement . . . ' or 'R . . . .'"**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | **Michael Calimano** | |
| Organization: | **New York Independent System Operator** | |
| Telephone: | **518-356-6129** | |
| E-mail: | **mcalimano@nyiso.com** | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
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| ☐ NA — Not Applicable | | |

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Contact Segment:

Contact Telephone:

Contact E-mail:

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   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time.

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   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☒ Yes

   ☐ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   **The NYISO also supports the IRC comment that the Reliability Coordinators should not be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2).**

   **Also, guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document.**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **John Bussman** | | |
| Organization: **AECI** | | |
| Telephone: **417-885-9216** | | |
| E-mail: **jbussman@aeci.org** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☒ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☐ No

   Comments Basically they do, however AECI does not believe that .85 pu for calculations is necessary. Our standards used 1.0 pu.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

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   Explanation for selection: Everyone needs to set their relays with consistency throughout the region. This will ensure that the way the settings are calculated will be the same for all regions. Any change to the reference will require a change to the standard.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☐ Yes

   ☒ No

If no, please identify which effective date should be modified and identify why. The Transmission owners need enough time to prepare the calculation, determine setting and plan setting changes within their region. One year after board approval should be enough time.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**See SERC comments for the Level of non compliance section comments.**

**In R1. We are not sure of the basis for the .85pu voltage and 30 degrees phase angle.**

**R1.3.1 Agree with the SERC comment of the inconsistency of .85 vs 1.0 pu.**

**Agree with SERC commnets regarding R1.6 R1.9 and R2**

**R1.5 We are concerned on how the transmission line being fed from a "weak source" can be protected if the line relays are set to not operate at or below 170% of the maximum end-of-line three-phase fault magnitude. It would seem that if a fault condition did exist at the end of the line, the relay would not clear this fault and would just serve it as load. More clarification is required regarding this setting**

**How does this standard apply to tapped lines that are greater than 200KV when the relays are set to trip the tapped line however not the main feeder line.**

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|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **Pepco Holdings, Inc - Affiliates**

Lead Contact: **Richard Kafka**

Contact Organization: **Pepco Holdings, Inc. - PHI**

Contact Segment: **1**

Contact Telephone: **301-469-5274**

Contact E-mail: **rjkafka@pepcoholdings.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Alvin Depew | Potomac Electric Power Co. | RFC | 1 |
| Carl Kinsley | Delmarva Power | RFC | 1 |
| Evan Sage | Potomac Electric Power Co. | RFC | 1 |
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   ☒ Yes

   ☐ No

   Comments PHI supports the complete set of comments of the NERC System Protection and Control Task Force (SPCTF) for this standard. We will not repeat them in our comments.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

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5. Do you agree with the proposed effective dates?

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   ☐ No

If no, please identify which effective date should be modified and identify why.

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   ☒ Yes

   ☐ No

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   **See SPCTF comments**

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | **Roger Champagne** |
| Organization: | **Hydro-Québec TransÉnergie** |
| Telephone: | **514 289-2211 X 2766** |
| E-mail: | **champagne.roger.2@hydro.qc.ca** |

| NERC Region | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ ECAR | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ No

   Comments

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   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

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   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

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**Hydro-Québec TransÉnergie (HQTÉ) is concerned about the Applicability of the standard (section A 4.1). It appears the standard applies to elements based solely on their voltage level.**

**It should be clarified that the standard applies only to BPS equipments. As a member of NPCC, HQTÉ have been using a performance based criteria to determine such equipments rather than using the voltage level.**

**HQTÉ has also an issue about some specific application of the standard.**

**In particular, for a portion of our 315 kV system, the standard as written cannot be complied with for technical reasons due to the system characteristics. We had to apply for technical exception.**

**Also, in relation to the hot spot winding protection for all 735 kV transformers, HQTÉ practice for overloading those transformers imposes additional safety margins than what is proposed in IEEE C57.91 -1995. Again, HQTÉ will have to apply for technical exception.**

**These technical exceptions will not affect the reliability of the system.**

**The standard should be less specific to allow for such technical conditions. If technical exceptions are permitted, this should be indicated in the standard.**

**HQTÉ suggest the addition of two more elements in item 1.2 of Attachment A:**
**1) Relay elements associated with DC lines**
**2) Relay elements associated with transformers at converter station.**

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**Group Comments (Complete this page if comments are from a group.)**

Group Name: **SCE&G ERO Working Group**

Lead Contact: **Sally Ballentine Wofford**

Contact Organization: **South Carolina Electric & Gas Company**

Contact Segment: **Transmission**

Contact Telephone: **803-217-9343**

Contact E-mail: **sbwofford@scana.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Lee Xanthakos | South Carolina Electric & Gas Co | SERC | 1 |
| Hubert C. Young | South Carolina Electric & Gas Co | SERC | 3 |
| Richard Jones | South Carolina Electric & Gas Co | SERC | 5 |
| Henry Delk | South Carolina Electric & Gas Co | SERC | |
| Jonh T. Blalock | South Carolina Electric & Gas Co | SERC | |
| Dan Goldston | South Carolina Electric & Gas Co | SERC | |
| Todd Johnson | South Carolina Electric & Gas Co | SERC | |
| Jay Hammond | South Carolina Electric & Gas Co | SERC | |
| Phil Kleckley | South Carolina Electric & Gas Co | SERC | |
| Pat Longshore | South Carolina Electric & Gas Co | SERC | |
| Simon Shealy | South Carolina Electric & Gas Co | SERC | |
| Bob Smith | South Carolina Electric & Gas Co | SERC | |
| Andy Bowden | South Carolina Electric & Gas Co | SERC | |
| Arnie Cribb | South Carolina Electric & Gas Co | SERC | |
| Marion Frick | South Carolina Electric & Gas Co | SERC | |
| Ernie Gibbons | South Carolina Electric & Gas Co | SERC | |
| Jerry Lindler | South Carolina Electric & Gas Co | SERC | |
| Wayne Stuart | South Carolina Electric & Gas Co | SERC | |
| Brad Stokes | South Carolina Electric & Gas Co | SERC | |
| Shawn McCarthy | South Carolina Electric & Gas Co | SERC | |
| Ernie Mehaffey | South Carolina Electric & Gas Co | SERC | |
| Rick Lytle | South Carolina Electric & Gas Co | SERC | |

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3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

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   ☐ Yes

   ☒ No

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☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why.
Utilities should be given more time, at least 2 years after BOT approval, to meet these requirements. One year to budget and plan and another year to implement

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Requirements Section:**

**R1 Opening paragraph: "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees. Suggest that this sentence be clarified to state that it applies only to relays sensitive to voltage and/or power factor angle.**

**R1.2.1 and R1.3.2 Reference Document - The calculation of maximum power transfer at 1.0 per unit seems to be inconsistent with the use of 0.85 pu voltage for the relay load limit.**

**R1.5 Reference Document - More explanation is needed to avoid confusion.**

**R2 In the text of R2, R.13 should be R1.13. R2.1 and R2.2 appear to be easily combined.**

**Non-Compliance Levels**

**Suggest that non-compliance levels 3 & 4 be exchanged. It seems that non-compliance resulting in a reportable disturbance is more serious than ….evidence does not support….**

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| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☐ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — RTOs, ISOs, Regional Reliability Councils |
| | ☐ | 3 — Load-serving Entities |
| | ☐ | 4 — Transmission-dependent Utilities |
| | ☐ | 5 — Electric Generators |
| | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| | ☐ | 7 — Large Electricity End Users |
| | ☐ | 8 — Small Electricity End Users |
| | ☐ | 9 — Federal, State, Provincial Regulatory, or other Government Entities |

**Group Comments (Complete this page if comments are from a group.)**

Group Name: **PJM Reliabilty Services Division**

Lead Contact: Thomas Bowe

Contact Organization: PJM

Contact Segment: 2

Contact Telephone: (610) 666 - 4776

Contact E-mail: bowet@pjm.com

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
|---|---|---|---|
| Albert DiCaprio | PJM | RFC | 2 |
| Mark Kuras | PJM | RFC | 2 |
| Robert Thomas | PJM | RFC | 2 |
| Joe Burdis | PJM | RFC | 2 |
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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. The 2003 blackout analyses showed that relay loadability played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by "zone 3" relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

The purpose of the proposed Standard is to ensure that protection systems and settings will neither limit transmission loadability, nor contribute to cascading outages.

NERC's System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF's Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line.

## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the “NERC Recommendation 8a Review” and the “Protection System Review Program – Beyond Zone 3”. Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☒ Yes

   ☐ No

   Comments

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an ‘Attachment’ to the standard and made mandatory **or** provided as a ‘Voluntary Reference’ outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: PJM supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

   If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

   ☐ Yes

   ☒ No

   If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why. A risk factor of High for a requirment that is related to a methodology seems excessive. Not using the suggested criteria will not de facto cause instability or cascading et al.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

   **Level 2 needs to be reworded . Level 2 implies "that evidence of COMPLIANCE exists" then states that the evidence is incomplete. Either it is compliant or it is incomplete.**

   **The Level 3 and Level 4 non compliance seems to be reversed. Level 3 seems to be related to a more adverse result than does Level 4.**

   **Reliability Coordinators are responsible for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The verification of relay settings is more appropriate at the Transmission Operator level.**

This form must be used to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **September 29, 2006.** You must submit the completed form by e-mail to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line. If you have questions please contact Richard Schneider at richard.schneider@nerc.net or 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: **Carol Gerou** | | |
| Organization: **Minnesota Power** | | |
| Telephone: **218-722-1972 ext. 2058** | | |
| E-mail: **cgerou@mnpower.com** | | |
| NERC Region | | **Registered Ballot Body Segment** |
| ☐ ERCOT<br>☐ ECAR<br>☐ FRCC<br>☐ MAAC<br>☐ MAIN<br>☒ MRO<br>☐ NPCC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA — Not Applicable | ☒ | 1 — Transmission Owners |
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**Group Comments (Complete this page if comments are from a group.)**

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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* If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information:**

Protective relays have often contributed to system disturbances including the Northeast Blackout of 1965, and the Blackout of August 14, 2003. The 2003 blackout analyses showed that relay loadability played a pivotal role in accelerating and spreading the early part of the cascade in Ohio and Michigan. Although the U.S.-Canada Power System Outage Task Force focused on the role played by "zone 3" relays, it was later found that other phase-distance and over-current relays also contributed to the cascade.

The purpose of the proposed Standard is to ensure that protection systems and settings will neither limit transmission loadability, nor contribute to cascading outages.

NERC's System Protection and Control Task Force produced a reference document to assist entities in understanding the standard. You are encouraged to read the reference document with the standard before responding to the comments on the Transmission Relay Loadability standard. If you have comments on the SPCTF's Transmission Relay Loadability reference document, please e-mail those comments in a separate Word document to sarcomm@nerc.com with the words "Relay Loadability Comments" in the subject line.

## Please Enter All Comments in Simple Text Format.

1. Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

   ☐ Yes

   ☒ No

   Comments R1.6 through R1.13 will need have a closer look to see if they match NERC 8A. Plus, at the moment the MRO does not not want to define the critical lines.

2. Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory **or** provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.

   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection: Reference documents are too specific.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☒ Yes

   ☐ No

   If yes, please identify the regional difference. Special protection schemes, system stability criteria, varying operating procedures.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

   ☒ Yes

   ☐ No

If no, please identify which effective date should be modified and identify why.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**7a. The purpose (A3) should change from, "Protective relay settings shall not limit transmission loadability." to, "In most cases Protective relay settings should not limit transmission line loadability." There are a-typical applications where relays need to limit the loadability of a line.**

**7b. We need a better method to apply for an exception.**

**7c. In R.1.11 and the second method to set relays. The temperatures for the top oil and winding hot spot should be expressed as % of transformer insulation.**

**7d. R2.1 & R2.2 should be combined.**

**7e. In CM2, the relays should be set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13.**

**7f. In the attachment A, the main sentence should have the "trip" reference removed to read, "This standard addresses any potective functions which could operate with or without time delay, on load current, including but not limited to:" This change in the verb would agree with protective function 1.1.3 out-of-step blocking.**

**7g. In D2.1.1, "…, or R.13 …" should change to "…, or R1.13 …".**

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| NERC Region | | **Registered Ballot Body Segment** |
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| **Group Comments (Complete this page if comments are from a group.)** | | | |
|---|---|---|---|
| Group Name: **SERC Protection and Control Subcommittee** | | | |
| Lead Contact: **Bridget Coffman** | | | |
| Contact Organization: **South Carolina Public Service Authority** | | | |
| Contact Segment: **1** | | | |
| Contact Telephone: **(843) 761-8000** | | | |
| Contact E-mail: **blcoffma@santeecooper.com** | | | |
| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
| **Susan Morris** | **SERC Reliability Organization** | **SERC** | **2** |
| **Phil Winston** | **Georgia Power Company** | **SERC** | **1** |
| **Ernesto Paon** | **MEAG** | **SERC** | **1** |
| **Sonia Walden** | **Dominion Virginia Power** | **SERC** | **1** |
| **Marion Frick** | **South Carolina Electric & Gas Co** | **SERC** | **1** |
| **Steve Waldrep** | **Georgia Power Company** | **SERC** | **1** |
| **Charlie Fink** | **Entergy** | **SERC** | **1** |
| **Paul Smith** | **Duke Energy Carolinas** | **SERC** | **1** |
| **Jay Farrington** | **Alabama Electric Cooperative,Inc** | **SERC** | **1** |
| **George Pitts** | **Tennessee Valley Authority** | **SERC** | **1** |
| **Robert Rauschenbach** | **Ameren Services Company** | **SERC** | **1** |
| Hong Ming Shuh | Georgia Transmission Corp | SERC | 1 |
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**Background Information:**

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   ☒ Yes

   ☐ No

   Comments

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   ☐ Reference should be made a mandatory part of the standard

   ☒ Reference should be made available as a voluntary reference without mandatory compliance

   Explanation for selection:

   It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the Standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website.

3. Are you aware of any regional differences that would be required as a result of this standard?

   ☐ Yes

   ☒ No

   If yes, please identify the regional difference.

4. Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?

   ☐ Yes

   ☒ No

   If yes, please identify the conflict, being as specific as possible.

5. Do you agree with the proposed effective dates?

☐ Yes

☒ No

If no, please identify which effective date should be modified and identify why. Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation, i.e., 2 years from NERC BOT approval.

6. Do you agree with the proposed violation risk factors?

☒ Yes

☐ No

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:

**Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.**

**Requirements section:**

**Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.**

**R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.**

**R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion.**

**R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become outaged is forseable (i.e. one line is out for maintenance and a fault occurrs on the second line), applying this scenario to more multiples becomes more and more unlikely.**

**R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.**

**R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings.**

The Relay Loadability Standard Drafting Team thanks all commenters who submitted comments on the 1st of the Relay Loadability standard. This standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The Relay Loadability Standard Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 36 sets of comments, including comments from more than 100 different people from more than 50 companies representing 6 of the 9 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is posting this standard for another comment period.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Relay-Loadability.html

## Summary of Major Changes:

- Most stakeholders who submitted comments on the proposed standard agree that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Stakeholders are also in general agreement that the Reference Document should be made available as a voluntary reference and as a result the reference document will be listed in the standard as a reference but will not be made a part of the standard.
- Added the Reliability Coordinator as a responsible entity and added a requirement for the Reliability Coordinator to determine which of the facilities within its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System.
- Made the following technical clarifications based on stakeholder comments:
    - Modified R1 by adding the phrase, "for any specific circuit terminal" to add more definition to the scope of the requirement.
    - Modified R1.3 to clarify that, when setting transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability, entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit.
    - Modified R1.3.2 to clarify that it is not the 'per unit bus voltage at each end of the line' that should be used when performing the power transfer calculation, but the 'per unit voltage behind each source impedance' that should be used.
    - Modified the scope of R1.10 to add transmission line relays on transmission lines terminated only with a transformer
    - Modified R1.12 to add the parenthetical phrase shown as follows:

        When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to . . .

- Modified Requirement 2 to clarify that the responsible entity must obtain, 'agreement from its Planning Authority, Transmission Operator and Reliability Coordinator' rather than 'approval of its Regional Reliability Organization and Reliability Coordinator' prior to using the criteria in R1.6, etc.
- Modified the Attachment to clarify that overload protection with a fifteen minute or longer response time is excluded from this standard.
- Modified the Attachment to clarify that out-of-step blocking schemes must be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.
- Modified the Attachment to clarify that relay elements associated with DC lines and relay elements associated with transformers at converter stations are covered by this standard.

- No significant regional differences or conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement were identified.
- Many of the stakeholders did not agree with the effective dates of the standard and these were changed to bring them into conformance with the format requested by the Compliance Program and to reflect that the effective dates are linked to the approvals from applicable regulatory authorities. If entities conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the System Protection and Control Task Force (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The drafting team did include, in the implementation plan and the revised effective dates, language to indicate that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be translated and respected. Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant.
- A number of stakeholders indicated that they feel the violation risk factors are too high, but most agreed with the proposed risk factors and with the exception of the rating for R2, the violation risk factors were not changed. The rating for R2 was changed from lower to medium, to align with the changes made to the requirement based on stakeholder feedback.
- A new version of the *Reliability Standards Development Procedure Manual* was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised manual or to conform to the ERO Rules of Procedure:

  – **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of Mitigation Time Horizons as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing mitigation time horizons for each requirement:
    - ***Long-term Planning:*** a planning horizon of one year or longer.
    - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
    - ***Same-day Operations****:* routine actions required within the timeframe of a day, but not real-time.
    - ***Real-time Operations****:* actions required within one hour or less to preserve the reliability of the bulk electric system.
    - ***Operations Assessment***: follow-up evaluations and reporting of real time operations.

- **Levels of Non-compliance Versus Violation Severity Levels**

  The drafting team deleted 'levels of non-compliance' and added 'violation severity levels' to comply with the revised Reliability Standard Development Procedure Manual. Compliance personnel assisted the drafting team in using the following criteria from the manual to establish violation severity levels:
  - ***Lower:*** mostly compliant with minor exceptions — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
  - ***Severe:*** poor performance or results — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**

  The drafting team added a section 'F' to the standard called, 'Associated Documents' to list items such as forms, related standards, reports, etc.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

| Commenter | Company | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| John F. Bussman | AECI | ✓ | | | | | | | | |
| James H. Sorrels, Jr. | AEP | ✓ | | | | ✓ | ✓ | | | |
| Anita Lee | AESO | | ✓ | | | | | | | |
| Ken Goldsmith | ALT | | ✓ | | | | | | | |
| Robert Rauschenbach | Ameren | ✓ | | | | | | | | |
| Mike McDonald (NERC SPCTF) | Ameren | | | | | | | | | |
| Henry Miller (NERC SPCTF) | American Electric Power | | | | | | | | | |
| Mike Gentry (WECC RCWG) | APS | | ✓ | | | | | | | |
| Baj Agrawal (NERC SPCTF) | Arizona Public Service | | | | | | | | | |
| Dave Rudolph | BEPC | | ✓ | | | | | | | |
| Lorissa Jones | BPA Transmission | ✓ | | | | | | | | |
| Dean Bender | BPA Transmission | ✓ | | | | | | | | |
| Brenda Coopernoll | BPA Transmission | ✓ | | | | | | | | |
| Jon Duame | BPA Transmission | ✓ | | | | | | | | |
| Brent Kingsford | California ISO | | ✓ | | | | | | | |
| Greg Tillitson (WECC RCWG) | CMRC | | ✓ | | | | | | | |
| Ed Thompson (CP9 RSWG) | ConEd | ✓ | | | | | | | | |
| Tom Weidman (NERC SPCTF) | Consultant | | | | | | | | | |
| Richard G. Cottrell | Consumers Energy | | | ✓ | ✓ | | | | | |
| Carl Kingsley | Delmarva Power | ✓ | | | | | | | | |
| Ed Davis | Entergy Services, Inc. | ✓ | | | | | | | | |
| H. Steven Myers | ERCOT | | ✓ | | | | | | | |
| William Miller (NERC SPCTF) | Exelon | | | | | | | | | |
| David Folk | First*Energy* | ✓ | | ✓ | | ✓ | ✓ | | | |
| John E. Odom, Jr. | FRCC | | ✓ | | | | | | | |
| Eric Senkowicz | FRCC | | ✓ | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Phillip Winston (NERC SPCTF) | Georgia Power Co. | | | | | | | | | |
| Phil Winston | Georgia Power Company | | | ✓ | | | | | | |
| Dick Pursley | GRE | | ✓ | | | | | | | |
| John Ciufo (NERC SPCTF) | Hydro One | | | | | | | | | |
| David Kiguel | Hydro One Networks Inc. | ✓ | | ✓ | | | | | | |
| Dave Angell (NERC SPCTF) | Idaho Power | | | | | | | | | |
| Ron Falsetti | IESO | ✓ | | | | | | | | |
| Bill Shemley (CP9 RSWG) | ISO New England | | ✓ | | | | | | | |
| Charles Yeung – SPP | ISO/RTO Council | | ✓ | | | | | | | |
| Thomas Bowe – PJM | ISO/RTO Council | | ✓ | | | | | | | |
| Peter Brandien – ISO-NE | ISO/RTO Council | | ✓ | | | | | | | |
| Michael Calimano – NYISO | ISO/RTO Council | | ✓ | | | | | | | |
| John Dumas – ERCOT | ISO/RTO Council | | ✓ | | | | | | | |
| Ron Falsetti – IESO | ISO/RTO Council | | ✓ | | | | | | | |
| Roger Champagne | Hydro-Québec TransÉnergie | ✓ | | | | | | | | |
| Brent Kingsford – CAISO | ISO/RTO Council | | ✓ | | | | | | | |
| Anita Lee – AESO | ISO/RTO Council | | ✓ | | | | | | | |
| Bill Phillips – MISO | ISO/RTO Council | | ✓ | | | | | | | |
| Jim Cyrulewski | JDRJC | ✓ | | | | | | | | |
| Eric Ruskamp | LES | | ✓ | | | | | | | |
| Robert Coish (NERC SPCTF) | Manitoba Hydro | | | ✓ | | ✓ | ✓ | | | |
| Don Nelson (CP9 RSWG) | Mass. Dept. of Tele. and Energy | | | | | | | | | ✓ |
| Tom Mielnik | MEC | | ✓ | | | | | | | |
| Tim Bartel | Minnkota Power Coop | | | | | | | | | |
| Terry Bilke | MISO | | ✓ | | | | | | | |
| Don Raveling | Montana-Dakota Utilities | ✓ | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Carol Gerou | MP | | ✓ | | | | | | | |
| Larry E. Brusseau | MRO | | ✓ | | | | | | | |
| Joseph Knight | MRO | | ✓ | | | | | | | |
| Herb Schrayshuen | National Grid | ✓ | | | | | | | | |
| Phillip Tatro (NERC SPCTF) | National Grid USA | | | | | | | | | |
| Robert Cummings (NERC SPCTF) | NERC | | | | | | | | | |
| David Taylor | NERC | | | | | | | | | |
| Jim Ingleson (CP9 RSWG) | New York ISO | | ✓ | | | | | | | |
| Ralph Rufrano (CP9 RSWG) | New York Power Authority | ✓ | | | | | | | | |
| Al Adamson (CP9 RSWG) | New York State Relia. Council | | ✓ | | | | | | | |
| Mike Gopinathan (CP9 RSWG) | Northeast Utilities | ✓ | | | | | | | | |
| Guy V. Zito (CP9 RSWG) | NPCC | | ✓ | | | | | | | |
| Guy V. Zito | NPCC | | ✓ | | | | | | | |
| Al Boesch | NPPC | | ✓ | | | | | | | |
| Michael Calimano | NYISO | | ✓ | | | | | | | |
| Mark Ringhausen | Old Dominion Electric Coop. | | | | ✓ | | | | | |
| Todd Gosnell | OPPD | | ✓ | | | | | | | |
| Alvin Depew | Pepco | ✓ | | | | | | | | |
| Evan Sage | Pepco | ✓ | | | | | | | | |
| Richard Kafka | Pepco Holdings, Inc. | ✓ | | | | | | | | |
| Joe Burdis (NERC SPCTF) | PJM | | | | | | | | | |
| Al DiCaprio | PJM Reliability Services Division | | ✓ | | | | | | | |
| Mark Kuras | PJM Reliability Services Division | | ✓ | | | | | | | |
| Robert Thomas | PJM Reliability Services Division | | ✓ | | | | | | | |
| Joe Burdis | PJM Reliability Services | | ✓ | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| | Division | | | | | | | | | |
| D. Bryan Guy | Progress Energy – Carolinas | ✓ | | ✓ | | ✓ | | | | |
| Steve Johnson (WECC RCWG) | RDRC | | ✓ | | | | | | | |
| Frank McElvain (WECC RCWG) | RDRC | | ✓ | | | | | | | |
| Robert W. Millard | RFC | | ✓ | | | | | | | |
| Jon Sykes (NERC SPCTF) | Salt River Project | | | | | | | | | |
| Neil Shockey | SCE | ✓ | | | | | | | | |
| Bridget Coffman (SCPSA) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Susan Morris (SERC RO) | SERC Protection & Control Subc. | | ✓ | | | | | | | |
| Phil Winston (Georgia Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Ernesto Paon (MEAG) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Sonia Walden (DOM VA Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Marion Frick (SC&EG) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Steve Waldrep (Georgia Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Charlie Fink (Entergy) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Paul Smith (Duke – Carolinas) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Jay Farrington (Al. Elec. Coop) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| George Pitts (TVA) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Robert Rauschenbach (Ameren) | SERC Protection & Control | ✓ | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| | Subc. | | | | | | | | | |
| Hong Ming Shuh (GA Trans. Corp.) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Patrick Huntley | SERC RC | | ✓ | | | | | | | |
| Jim Busbin | So. Company Services, Inc. | ✓ | | | | | | | | |
| J.T. Wood | So. Company Services, Inc. | ✓ | | | | | | | | |
| Roman Carter | So. Company Services, Inc. | ✓ | | | | | | | | |
| Nancy Wofford (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Lee Xanthakos (SCE&G ERO WG) | South Carolina Electric & Gas | ✓ | | | | | | | | |
| Hubert C. Young (SCE&G ERO WG) | South Carolina Electric & Gas | | | ✓ | | | | | | |
| Richard Jones (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | ✓ | | | | |
| Henry Delk (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| John T. Blalock (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Dan Goldston (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Todd Johnson (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Jay Hammond (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Pat Longshore (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Simon Shealy (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Bob Smith (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Andy Bowden (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Arnie Cribb (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Marion Frick (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Jerry Lindler (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Wayne Stuart (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Brad Stokes (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Shawn McCarthy (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Ernie Mehaffey (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Rick Lytle (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Neil Shockey | Southern California Edison | ✓ | | | | | | | | |
| Terry Crawley | Southern Nuclear | | | | | ✓ | | | | |
| Wayne Guttormson | SPC | | ✓ | | | | | | | |
| Mark Nagle | SPP | | ✓ | | | | | | | |
| Makarand Nagle | SPP | | ✓ | | | | | | | |
| Roger Champagne (CP9 RSWG) | TransÉnergie Hydro-Québec | ✓ | | | | | | | | |
| John D. Roberts (NERC SPCTF) | TVA | | | | | | | | | |
| Nancy Bellows (WECC RCWG) | WAPA | | ✓ | | | | | | | |
| Deven Bhan (NERC SPCTF) | WAPA | | | | | | | | | |
| Darrick Moe | WAPA | | ✓ | | | | | | | |
| Kenneth J. Wilson | WECC | | ✓ | | | | | | | |
| Jim Maenner | WPS | | ✓ | | | | | | | |
| Pam Oreschnick | XEL | | ✓ | | | | | | | |

## Index to Questions, Comments and Responses

1. **Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3".**

Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

**Summary Consideration:** Most stakeholders agree that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". There were several suggestions for minor edits and changes. The drafting team made the following changes to the standard based on stakeholder comments:

- Added the Reliability Coordinator as a responsible entity and added a requirement for the Reliability Coordinator to determine facilities critical to the reliability of the electric system.
- Modified the Attachment to indicate that overload protection with a fifteen minute or longer response time is excluded from this standard
- Modified the Attachment to clarify that out-of-step blocking schemes must be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MRO (2) et al<br>Joseph Knight<br><br>Manitoba Hydro (3, 5, 6)<br>Robert Coish | | | The MRO (Manitoba Hydro) generally believes this standard addresses the industry action listed above but has some significant reservations about how the standard is written as well as concerns about potential risks to reliability if this standard is implemented.<br><br>1) This standard should be more directly based on the concept that collapse should be slowed or delayed to the extent of the thermal capability of facilities. Suggest the purpose statement read - Protective relay settings shall not limit transmission loadability uncontrolled collapse is slowed or delayed to the extent of the thermal capability of facilities. The proposed standard should make direct reference to the additional time this standard is targeting to give the operators to respond to an emergency situation. In the current draft there is a rather indirect reference to 15 minutes.<br><br>(2) The MRO (Manitoba Hydro) s concerned that this standard is removing some inherent thermal overload protection from the bulk electric system. In its response to comments the SAR drafting team stated - The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides (admittedly crude) overload protection and MRO (Manitoba Hydro) believes there is increased inhent risk to the bulk electric system in the sentiment of the SAR drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| | | | always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes. - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? The MRO (Manitoba Hydro) believes that a risk analysis should be conducted before implementing this standard.<br><br>(3) The MRO (Manitoba Hydro) believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with rgard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive.<br><br>(4) The SAR designates that this standard shall also be applicable to the Regional Reliability Organization. In its response to comments the SAR drafting team stated - It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include these clarifications. - However, there are no requirements on the RRO in this standard. Specifically, where in the standards is the RRO required to identify lines/transformers critical to the reliability of the electric system? If it is even appropriate for the RRO to come up with the methodology, the needed requirements on the RRO should include a requirement to develop the methodology in coordination with the RC, PA and the TO.<br><br>(5) In 4.1.2 and 4.1.4, the words "as designated by the Regional Reliability Organization as critical to the reliability of the electric system" are not consistent with those used in the SAR (operationally significant circuits, etc.).<br><br>(6) if during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wavetraps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of service on time? |
| Response:<br>(1) The required operator response is defined in TOP-008 and it is inappropriate to repeat this requirement in this standard. Overload protection with a fifteen minute or longer response time has been added to the protection systems excluded from this standard, in Attachment A.<br>System protection systems must balance security and dependability. Security means not tripping when you do not want to; dependability means tripping when you want to trip. Numerous companies have provided input to this standard. Some companies lean more towards security some lean more towards dependability. This standard represents an acceptable balance between the two. | | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| (2) System protection systems are designed to remove faults. Typically, system protection criteria do not include preventing equipment damage from overload conditions. Operator action is required to protect facilities from overload conditions per NERC Standard TOP-008-0, R3. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond.<br>(3) Most stakeholders who responded seem to indicate support for this detail.<br>(4) The standard has been changed to assign a requirement to the Reliability Coordinator for this function.<br>(5) The Drafting Team revised these requirements to assign responsibility to the Reliability Coordinator; the language used in the standard has the same meaning as that in the SAR.<br>(6) Other NERC standards require facility ratings be defined and that the system be operated within those ratings. | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | See Comment # 7. RCCWG does not feel that this standard accurately addresses the Industry action due to the concerns stated. That said, to the extent that extreme emergency conditions can be identified in advance of their occurrence and simulated, this standard has addressed the stated concerns. |
| Response: See Drafting Team's response to your comment on question 7. | | | |
| Ameren (1)<br>Robert Rauschenbach | | ☑ | A more straight forward standard should be developed where the NERC formula is used for Relay Load Limit Calculations for 230 kV and above. The Relay Load Limit would then need to be used by Operations and Planning as a line limit not to be exceeded under the NERC Table 1 conditions. The conservative 0.85 per unit voltage and 1.5 current values used in the NERC formula would provide margin against relay trips under multiple contingencies / extreme emergencies.<br><br>This method would be more performance based and less prescriptive. It avoids the exceptions and their various interpretations, and allows utilities to set relays as needed to best provide a reliable system. Requiring the Relay Load Limit to exceed the maximum thermal rating does not make sense if the thermal capacity is not being used, but merely available for ultimate designs. The requirement to exceed maximum thermal rating is what ultimately leads to the need for exceptions and their interpretation.<br><br>A utility attempting to meet this standard may be providing less backup coverage when it is not necessary. This lack of backup could ultimately lead to reduced reliability or a blackout scenario due to an un-cleared fault on the system. |
| Response: Table 1 does not apply. This standard addresses conditions beyond Table 1 category C. System protection systems must balance security and dependability. Security means not tripping when you do not want to; dependability means tripping when you want to trip. Numerous companies have provided input to this standard. Some companies lean more towards security some lean more towards dependability. This standard represents an acceptable balance between the two. R1.2 – R1.13 are provided to specify rating conditions other than thermal which the relay loadability must address; use of these requirements allows maximum backup coverage. This standard requires that reliable protection | | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| Commenter | Yes | No | Comment |
| be provided while allowing transmission loadability. | | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑ | | The referenced activities seem to be all included in the requirements, but nothing additional seems to be included. However, the supporting information in the documents for the previous activities seems crucial to being able to meet the requirements |
| Response: The Reference Document and perhaps other documents will be provided as supporting material but will not be part of the standard. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | PRC-023 (Draft), in Appendix A, briefly mentions Switch-onto-Fault relaying and Out-of-Step Blocking and Tripping relaying, but very little else is said about these subjects, either in the Standard or in the Reference Paper. The above-referenced previous actions addressed these subjects in detail; SOTF is the subject of an informational paper by the SPCTF. We recommend that these subjects be addressed in more detail, particularly in the Reference Document. |
| Response: Two appendices (Appendix C — Out-of-step Blocking Relaying and Appendix D – Switch-on-to-Fault Scheme) have been added to the PRC-023 Reference Document to address your concerns. | | | |
| AECI (1)<br>John F. Bussman | ☑ | | Basically they do, however AECI does not believe that .85 pu for calculations is necessary. Our standards used 1.0 pu. |
| Response: The industry actions relate relay loadability to system collapse. Therefore the use of 0.85 pu voltage for relay performance calculations is appropriate. Studies into the various WECC collapses, into the 1967 blackout, and into August 2003 show that the system voltage becomes depressed during the pre-collapse time periods, and it is these time periods during which the evaluation of the relay performance is most critical. | | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | PHI supports the complete set of comments of the NERC System Protection and Control Task Force (SPCTF) for this standard. We will not repeat them in our comments. |
| Response: Acknowledged. Please see the responses to the SPCTF comments. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑ | | |
| Entergy Services, Inc. (1)<br>Ed Davis | ☑ | | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | ☑ | | |
| Hydro One Networks Inc. | ☑ | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| (1, 3) – David Kiguel | | | |
| IESO (2)<br>Ron Falsetti | ☑ | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | ☑ | | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑ | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| PJM Reliability Services Division – Al DiCaprio (2) | ☑ | | |
| ISO/RTO Council<br>Charles Yeung | ☑ | | |
| AESO (2)<br>Anita Lee | ☑ | | |
| FRCC (2)<br>Eric Senkowicz | ☑ | | |
| New York ISO (2) | ☑ | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Michael Calimano | | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| SCE (1)<br>Neil Shockey | ☑ | | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |
| SERC PCS<br>Susan Morris | ☑ | | |

2. **Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory or provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.**

   ☐ Reference should be made a mandatory part of the standard.

   ☐Reference should be made available as a voluntary reference without mandatory compliance.

**Summary Consideration:** Almost all stakeholders agree that the Reference Document should be made available a as a voluntary reference. As a result the reference document will be listed in the standard as a reference but will not be made a part of the standard.
The drafting team made the following conforming changes to the standard, based on stakeholder comments:

- Modified R1.3 to clarify that, when setting transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability, entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit.
- Modified R1.3.2 to clarify that it is not the 'per unit bus voltage at each end of the line' that should be used when performing the power transfer calculation, but the per unit voltage behind each source impedance that should be used.
- Modified R1.12 to add the parenthetical phrase shown as follows:
  When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>The reference provides additional explanations for the standard. It may be possible to comply with the standard without compliance to the reference, although I don't know how that would be done. To me this doesn't matter too much, but it perhaps would to a lawyer. What about the other reference documents on "out-of-step" and "3-terminal lines"? Would they be left as reference documents or become part of the standard too? Again they are helpful documents and provide good and helpful information but I think "Reference For Standard PRC-0230-1" is appropriate. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. The drafting team will review other available documents as other "Voluntary Reference Material". | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The RCCWG feels the standard should include all requirements. The reference document should remain a document that can be revised without requiring the standards process be followed. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Including the reference material with all of its technical exceptions into the standard would be confusing since the exceptions are similar to the standard's requirements but worded differently. However, attaching the non-mandatory reference material would serve as a historical record of development of the standard and may enhance the understanding of the standard. If future developments call for changes to the standards criteria, making the reference voluntary will allow it to remain as a background document. In addition, a citing for this reference material is needed in the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| Entergy Services, Inc. (1)<br>Ed Davis | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>Due to the technical complexities of the standard, the reference document is useful for providing guidance to achieve compliance. Although the document addresses the specific requirements and could possibly be used to determine compliance, it may not be all encompassing. It should not be used as a basis for determining any non-compliance and therefore should not be part of the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2)<br><br>New York ISO (2)<br>Michael Calimano | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| IESO (2)<br>Ron Falsetti | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. Should it be determined that aspects of the reference manual need to be mandatory and not a guideline they need to be incorporated into the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Hydro-Québec TransÉnergie | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| (1) – Roger Champagne | The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. That document should be referenced somewhere in the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The Reference material provides example calculations of how to accomplish the requirements included in the Loadability Standard. The Reference guide may need updated from time to time to stay current as an aid without the standard needing to be updated. The reference material does not add any requirements, it only explans how to meet the requirements contained in the Loadability Standard. Therfore, Reference Document should remain a separate document, but should be clearly referenced within the Loadability Standard so that it can be found and used to meet the Loadability Standard requirements. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Anything in the reference that should be mandatory shouled be included in the standards requriements not in an attachment. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>PEC believes the reference document separate but referenced in the standard making it available to easily correct if necessary. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>It seems to be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available such that it can be easily corrected if necessary. In order to support the tie between the Standard and the Reference Document, it seems that the Reference |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| | Document should be referenced within the standard, either via a statement within R1 such as "For additional guidance on these requirements, please see "PRC-023 Reference - Determination and Application of Practical Relaying Loadability Ratings", or via a similar footnoted reference on R1. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Without the reference document, it will be very difficult to accurately apply the standard. At the minimum, the Standard should clearly provide reference to Reference Document. The following question should be asked: Will auditors judge compliance with the Standard by applying the Reference Document? If so, maybe the Reference Document should be included in the standard. The only reason this commenter did not check the other box (reference part of the standard) is to avoid encumbering clarification/correction of the reference document when needed. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| NERC System Protection and Control Task Force<br>Jon Sykes<br><br>SERC PCS<br>Susan Morris | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the Standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| National Grid (1)<br>Herb Schrayshuen | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The entire Reference Document should not be incorporated in the standard; however, the standard Drafting Team should review the draft standard to ensure that adequate information is contained in each Requirement to ensure consistent interpretation and application. In some cases important information necessary to apply the stated Requirement is contained in text or a diagram within the Reference standard. Some examples that we find requiring further clarification include:<br>R1.3: Additional information is required regarding line resistance and the power angle between the sending and receiving line terminals.<br>R1.3.2: The reference to 1.05 p.u. voltage should identify this as the Thevenin equivalent source voltage |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| | behind the actual system source impedance at each end of the line, rather than at the end of the line.<br>R1.12: The maximum distance relay setting should clarify that the reach at the maximum torque angle (MTA) shall be set to provide no greater than 125% overreach at the impedance angle of the protected transmission line. The present language could be interpreted as requiring a setting of no more 125% of the line impedance magnitude applied at the MTA, which may not provide adequate protection coverage at the line impedance angle.<br>The Reference Document contains a significant volume of information to assist the industry in applying the standard. Additional information as noted above should be included in the standard, and the remaining information in the Reference Document should be posted with the standard on the NERC website as a separate reference source. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided.<br>R1.3 was modified to add more information to clarify that entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit<br>R1.3.2 was modified as suggested and now states:<br>An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.<br>R1.12 was modified to add the parenthetical phrase shown as follows:<br>When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints: | |
| PJM Reliability Services Division – Al DiCaprio (2) | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>PJM supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. | |
| AESO (2)<br>Anita Lee<br><br>ISO/RTO Council<br>Charles Yeung | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>The AESO (IRC) supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents. Unless the material in the Technical Requirement is required, then the Reference Document should be kept separate from the standard. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. | |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| FRCC (2)<br>Eric Senkowicz | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The reference document should be made "voluntary" in order to preserve and maintain the clarity of the requirements within the standard. The current compliance programs are not designed to interpret and measure reference documents and therefore would make compliance enforcement to another "type" of document inappropriate, difficult and confusing, especially with regard to the technical nature of the content. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Southern Company Transmission agrees with the explanation for this selection made by the SERC Protection and Control Subcommittee and the NERC System Protection and Control Task Force. Their explanations state, "It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website." |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>In its response to comments the SAR drafting team stated that - the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. Manitoba Hydro agrees with this approach of the SAR drafting team. The reference document should not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. Manitoba Hydro recognizes the value of the reference document as a guide and the hard work that went into preparing it. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| MRO (2) et al<br>Joseph Knight | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>(1)In its response to comments the SAR drafting team stated that<br>- the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. The MRO agrees with this approach of the SAR drafting team. The reference document should |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| | not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. The MRO recognizes the value of the reference document as a guide and the hard work that went into preparing it.<br><br>(2) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states generator protection relays are excluded from requirements of this PRC-023-1 standard(Page 1,section 2.3,reference document). The attachment A (section 1.2.4) to standard PRC-023-1 states generator protection relays that are susceptible to load are excluded from requirements of this PRC-023-1 standard. Should the attachment A of the standard be consistent with the reference document for the standard?<br><br>(3) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 9 states 200% of aggregated generation nameplate capability when the standard lists 230% of aggregated generated nameplate capability. (section R1.6) Why is the standard 230% when its reference document uses 200%?<br><br>(4) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 14 "If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100°C and 140 C respectively, justification for the reduced temperature must be provided." Where as in the standard (section R.11, last part), the standard states "Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100 C for the top oil or 140°C for the winding hot stop temperature." Shouldn't the reference document be consistent with the standard? (Where anything less than 100°C and 140 C would have justification associated with it.) |
| Response: (1) The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided.<br>(2) Changes were made to the reference document to correct the inconsistency between Attachment A and the reference document.<br>(3) An additional 115% factor is included in the green highlighted box in the Reference Document (Clause R1.6).<br>(4) Changes have been made to the reference document to make it consistent with the standard. | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| SCE (1)<br>Neil Shockey | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| Hydro One Networks Inc. (1, | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| 3) – David Kiguel | |
| So. California Edison (1)<br>Neil Shockey | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| NERC Regional Reliability Standards Working Group<br>David Taylor | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| Ameren (1)<br>Robert Rauschenbach | ☑ Reference should be made a **mandatory** part of the standard.<br><br>With the way the present standard is written, the reference document is necessary. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| AECI (1)<br>John F. Bussman | ☑Reference should be made a **mandatory** part of the standard.<br><br>Everyone needs to set their relays with consistency throughout the region. This will ensure that the way the settings are calculated will be the same for all regions. Any change to the reference will require a change to the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑Reference should be made a **mandatory** part of the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| BPA Transmission (1)<br>Lorissa Jones | I don't see how you could be in compliance with one and not the other. The reference supplies necessary details and should be an attachment to the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |

### 3. Are you aware of any regional differences that would be required as a result of this standard?

**Summary Consideration:** Almost all stakeholders feel there are no regional differences. The two comments from the two stakeholders that feel there are regional differences have been addressed Based on stakeholder comments, the drafting team made the following change to the standard:

- A requirement was added for the Reliability Coordinator to determine critical facilities within its Reliability Coordinator Area.

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Ameren (1)<br>Robert Rauschenbach | ☑ | | The definition of 100-200 kV critical facilities is not defined and will lead to differences between regional interpretations. The requirements should be dropped for 100-200 kV. |
| Response: This responsibility has been reassigned from the RRO to the Reliability Coordinator which has the overall operating and planning responsibility for determining critical facilities within its jurisdiction. | | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | It is more difficult to make relays on long transmission lines comply with the standard. The WECC will be impacted more because of the number of long transmission lines in that region. |
| Response: Understood. This difficulty is one of the primary reasons for the diversity of criteria from which to choose. | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | There are, however, philosophical differences in the application of relays, even among neighbors. One example is that some entities do not utilize zone 3 relays, and others find zone 3 relaying to be a vital backup component to system protection. |
| Response: Acknowledged. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | | ☑ | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | | ☑ | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2) | | ☑ | |

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Ron Falsetti | | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | | ☑ | |
| JDRJC Associates (1)<br>Jim Cyrulewski | | ☑ | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | | ☑ | |
| So. California Edison (1)<br>Neil Shockey | | ☑ | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish | | ☑ | |
| NERC System Protection and Control Task Force<br>Jon Sykes | | ☑ | |
| National Grid (1)<br>Herb Schrayshuen | | ☑ | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | |
| ISO/RTO Council<br>Charles Yeung | | ☑ | |
| AESO (2)<br>Anita Lee | | ☑ | |
| FRCC (2)<br>Eric Senkowicz | | ☑ | |

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| New York ISO (2)<br>Michael Calimano | | ☑ | |
| So. Company Services, Inc. (1) – Jim Busbin | | ☑ | |
| AECI (1)<br>John F. Bussman | | ☑ | |
| MRO (2) et al<br>Joseph Knight | | ☑ | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | | ☑ | |
| SCE (1)<br>Neil Shockey | | ☑ | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | | ☑ | |
| SERC PCS<br>Susan Morris | | ☑ | |

4. **Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?**

**Summary Consideration:** Almost all stakeholders feel there are no conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement.
Based on stakeholder comments, the drafting team modified Requirement 2 in the standard to clarify that the responsible entity must obtain, 'agreement from its Planning Authority, Transmission Operator and Reliability Coordinator' rather than 'approval of its Regional Reliability Organization and Reliability Coordinator' prior to using the criteria in R1.6, etc. The drafting team added a sub-requirement to clarify that the responsible entity that uses the calculated circuit capability to meet the requirements in this standard must use the same calculated circuit capability as the Facility Rating of the circuit.

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| NERC Regional Reliability Standards Working Group<br>David Taylor | ☑ | | R2 of this draft standard requires the TO, GO, or DP to obtain approval from the RRO and RC prior to using the criteria established in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 for each circuit terminal using the listed criteria. By establishing an obligation on the TO, GO, or DP to follow RRO and RC approved criteria, this makes PRC-023-1 a "fill-in-the-blank" standard. Section 215 of the U.S. Federal Power Act does not allow enforcement of a reliability standard upon a bulk power system owner, operator or user, including the setting of financial penalties and sanctions, to the extent a portion of the requirements exists outside the standard. However, Section 215 of the U.S. Federal Power Act does allow for a Regional Entity to establish a regional reliability standard through a NERC approved procedure to make the requirements listed in R2 enforceable. Section 215 does not grant a similar right to the RC. Accordingly, the Regional Reliability Standards Working Group (RRSWG) recommends that references to the RC in R2 and M2 of this standard be removed.<br><br>The RRSWG suggests that if the intent of the drafting team is to have a regional reliability standard developed to support the NERC standard by stating approval criteria and requirements unique to the region developing the supporting standard, that the standard be revised to show in section A.4 that it is applicable to the Regional Entity (RE), not RRO, and to clearly identify the RE requirements and measurements. If, instead, the intent of the drafting team is not to have a regional reliability standard developed, the RRSWG suggests that R2 and M2 be deleted or refined to remove the "fill-in-the-blank" characteristics. To do so, the drafting team might consider the following refinement to R2 that would remove the "fill-in-the-blank" characteristics. The refinement would be to have the TO, GO, or DP develop documentation that demonstrates its application of R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 complies with the criteria in the PRC-023 Reference Document. This refinement may require an additional requirement of the entity to simply provide its relay application documentation to the RRO and the RC for its information and |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | use. The applicable measurement would be for the RRO to verify compliance with the PRC-023 Reference Document criteria. This refinement would also require the PRC-023 Reference Document to be incorporated as an attachment to the standard or written into the NERC standard as additional requirements.<br><br>It is not the intent of the RRSWG to be overly prescriptive here. It is only our intent to provide options to the drafting team which it might not have already considered. The RRSWG assumes the drafting team will implement the appropriate revisions to the draft standard. |
| Response: R2 has been changed to obtaining the agreement of the Planning Authority, Transmission Operator, and Reliability Coordinator with the resulting facility ratings. This change results only in the necessary notifications to assure that consistent facility ratings are used. | | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | |
| MRO (2) et al<br>Joseph Knight<br>Manitoba Hydro (3, 5, 6)<br>Robert Coish | | ☑ | However, there could be regulatory issues regarding, for example, vertical clearance issues, for the proposed overloading of lines. |
| Response: Fault protective relays are not intended to prevent code violations. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | | ☑ | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | |
| Ameren (1)<br>John Rauschenbach | | ☑ | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| NPCC CP9 Reliability Standards Working Group | | ☑ | |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Guy Zito – NPCC (2) | | | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2)<br>Ron Falsetti | | ☑ | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | | ☑ | |
| JDRJC Associates (1)<br>Jim Cyrulewski | | ☑ | |
| So. California Edison (1)<br>Neil Shockey | | ☑ | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | |
| NERC System Protection and Control Task Force<br>Jon Sykes | | ☑ | |
| National Grid (1)<br>Herb Schrayshuen | | ☑ | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | |
| ISO/RTO Council<br>Charles Yeung | | ☑ | |
| AESO (2)<br>Anita Lee | | ☑ | |
| FRCC (2)<br>Eric Senkowicz | | ☑ | |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| New York ISO (2)<br>Michael Calimano | | ☑ | |
| So. Company Services, Inc. (1) – Jim Busbin | | ☑ | |
| AECI (1)<br>John F. Bussman | | ☑ | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | | ☑ | |
| SCE (1)<br>Neil Shockey | | ☑ | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | | ☑ | |
| SERC PCS<br>Susan Morris | | ☑ | |

5. **Do you agree with the proposed effective dates? If no, please identify which effective date should be modified and identify why.**

**Summary Consideration:** Many of the stakeholders do not agree with the effective dates of the standard. The drafting team did change the effective dates to bring them into conformance with the format requested by the Compliance Program and to reflect that the effective dates are linked to the approvals from applicable regulatory authorities and to clarify that Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.
Entities should already have taken steps to come into compliance with the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions). Entities should be in compliance with this proposed standard upon completion of the timetable for those Planning Committee activities.
Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, the revise effective dates give entities at least 39 months following applicable regulatory approvals to become compliant.

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | RCCWG feels that implementation should be delayed until # 7 comments are accommodated. |
| Response: The implementation plan was revised to include a statement indicating that Temporary Exceptions that have already been approved by the Planning Committee will be respected when the standard becomes effective. | | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | Both 5.1 and 5.2 should be on the same cycle. Recommend the effective date be 1/1/09 to allow time to address "lessons learned" after the 7/1/08 Beyond Zone 3 completion date. However, if staggered effective dates are used for these two requirements, they should be 6 months later than those stated to allow for incorporating "lessons learned". |
| Response: The industry has had since the end of 2004 to address lessons learned and no additional time is needed for that purpose.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Ameren (1)<br>Robert Rauschenbach | | ☑ | Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities | | | |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | We believe that entities should be allowed a 2 year period after FERC approval of the standard to become compliant with these kinds of standards that may require significant capital investment. First, entities should not be considered non-compliant with any requirements of any standard that is not FERC approved. Second, once the standard is approved by FERC the entity should have one year to analyze his system for compliance and to budget funds to replace needed euqipment. The second year would be needed to install the equipment and ensure the proper operation of the equipment. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | PEC believes that the Implementation Plan for PRC-023 should be changed. Those needing to comply will need at least two years to meet new requirements once they are finalized. One year to budget and plan, another for implementation. Therefore effective date should be two (2) years from NERC BOT approval. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | Utilities should be given more time, at least 2 years after BOT approval, to meet these requirements. One year to budget and plan and another year to implement. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| BPA Transmission (1)<br>Lorissa Jones | | ☑ | The proposed effective date of January 1, 2008 for transmission lines operated above 200 kV, etc. is appropriate, but the July 1, 2008 deadline for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100kV to 200 kV as designated by the regional reliability organization is not adequate because all of the regional reliability organizations have not yet designated which lines and transformers will fall under this requirement. The proposed effective date for these lines and transformers should be at least two years after the regional reliability organization has |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | designated the lines and transformers that are required to meet this reliability standard. |
| Response: The effective dates have been modified. Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| SERC PCS<br>Susan Morris | | ☑ | Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation, i.e., 2 years from NERC BOT approval. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| AESO (2)<br>Anita Lee | | ☑ | The effective date for the circuits described in 4.1.2 and 4.1.4 (transmission lines and transformers with low votage terminal at 100 kV to 200 kV) should be a certain time period after the determination by the Regional Reliability Organization of such circuits, rather than the proposed fixed effective date of July 1, 2008. This will address the concern that some RROs may be late in making those determinations. It is also not clear as to where is the requirement for the RROs to make such determination and how often a review should be made. |
| Response: The effective dates have been modified in response to comments. | | | |
| AECI (1)<br>John F. Bussman | | ☑ | The Transmission owners need enough time to prepare the calculation, determine setting and plan setting changes within their region. One year after board approval should be enough time. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish<br><br>MRO (2) et al<br>Joseph Knight | | ☑ | (1) The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RRO's are required to make this designation should be recommended by the SDT and added to the implementation plan.<br><br>(2) Regarding implementation plan, one would have expected an implementation time frame of the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven months after establishment of the |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC are depending on all participants to have proceeded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did? |
| Response: (1) The effective dates have been modified in response to comments. (2) If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the established and approved mitigation plan is followed. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | | ☑ | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | The implementation plan, however, should allow for previosly approved "Temporary Exceptions" to the criteria, within the Standard, as an approved mitigation plan with regard to Compliance Monitoring. The Compliance Monitoring should not result in a finding of non-compliance as long as the "Temporary Exception" mitigation plan is being followed. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the mitigation plan is followed. These previously-approved "Temporary Exceptions" will have been approved within the "NERC 8a" and/or "Beyond Zone 3" review process by the NERC System Protection and Control Task Force with the concurrence of the NERC Planning Committee. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | |
| NPCC CP9 Reliability Standards | ☑ | | |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Working Group<br>Guy Zito – NPCC (2) | | | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | ☑ | | |
| IESO (2)<br>Ron Falsetti | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| PJM Reliability Services Division – Al DiCaprio (2) | ☑ | | |
| ISO/RTO Council<br>Charles Yeung | ☑ | | |
| FRCC (2)<br>Eric Senkowicz | ☑ | | |
| New York ISO (2)<br>Michael Calimano | ☑ | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | |
| SCE (1)<br>Neil Shockey | ☑ | | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |

## 6. Do you agree with the proposed violation risk factors?

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

**Summary Consideration:** Most stakeholders agreed that the ratings are correct. The rating for R2 was changed from lower to medium, to align with the changes made to the requirement based on stakeholder feedback in response to other questions.

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | The Risk Factor for R1 should be Low. The standard may be new but the engineering of zone relay settings is not. Also it is unlikely that missing a setting will result in cascading outages. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish | | ☑ | Manitoba Hydro feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. | | | |
| MRO (2) et al<br>Joseph Knight | | ☑ | The MRO feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. | | | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | A risk factor of High for a requirement that is related to a methodology seems excessive. Not using the suggested criteria will not de facto cause instability or cascading et al. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| FRCC (2)<br>Eric Senkowicz | | ☑ | R1 should be a "medium" risk factor because of the inherent potential of mis-applied settings affecting BES system performance. However, an incorrect relay setting or a mis-applied relay settting, by itself, is unlikely to lead to the effects on the BES as described in the definition of a "high" risk factor. For the setting to affect the BES to the degree as described in the definition of "high" risk factor, multiple other core operational requirements would have had to have been violated. Therefore, for a mis-applied setting to affect the overall reliable response of a system to a particular disturbance, the effects on the system would be a result of multiple requirement |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | violations, including the lack of appropriate monitoring and analysis along with inadequate operator intervention at posturing an affected system,. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2)<br>Ron Falsetti | ☑ | ☑ | Agree with the violation risk factor for R.1 but not sure about the "Lower" ranking for R.2. The RRO or RC approval process only strengthens the standard apart from the fact that it provides a platform for communication between the RC and the transmission / generator owners who would primarily be responsible for the settings. Also, the RC or RRO would have a bigger picture of the various regions and it would be relatively easier for them to analyze the impacts of the various settings on a regional level as compared to a more localized level. |
| Response: In defining the VRFs the SDT felt that the APPROVAL of the RRO and RC (or lack thereof) was unlikely to directly impact a cascading event; thus the "lower" rating. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | What are the violation risk factors to be used for? |
| Response: The violation risk factors are one element used to determine an appropriate sanction. The sanctions guideline are posted on the NERC web site as Appendix 4 in NERC's ERO Application: http://www.nerc.com/~filez/ero/ero_applications.html | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | ☑ | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | Please note that only a VRF should be assigned to R1 since each of the sub clauses of R1 is a method for accomplishing the R1 requirement. |
| Response: Acknowledged. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | As reflected in the draft Standard, the VRF for R1 must apply to only R1 in its entirety, and not to each individual sub-clause of R1, in order to accurately reflect the phrase within R1, "any one of the following criteria..." |
| Response: Acknowledged. | | | |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| BPA Transmission (1)<br>Lorissa Jones | | | I think that the risk factor should be high. |
| Response: R1 is high. | | | |
| Ameren (1)<br>John  Rauschenbach | ☑ | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑ | | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑ | | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| New York ISO (2)<br>Michael Calimano | ☑ | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| AECI (1)<br>John F. Bussman | ☑ | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |

**7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:**

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| Montana-Dakota Utilities (1)<br>Don Raveling | Are there any recommendations for line thermal relays? Or, are they considered to be SPSs? |
| Response: No recommendations are being made relative to line thermal relays; Attachment A has been modified to specifically exclude protective elements that respond more slowly than 15 minutes. The unstated expectation is that line thermal relays will support the assigned Facility Rating. | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | Guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document. |
| Response: Appendix D has been added to the reference document to address SOTF. | |
| So. California Edison (1)<br>Neil Shockey | Reference R1.10 and R1.11 Is should be clear that where the relay protection referred to does not exist, that R1.10 and R1.11 are not requiring their installation, only describing their performance should they exist. |
| Response: The standard does not require that specific relays be present on the system. | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | R2, 2.1, 2.2, 2.3, and M2 all require the Regional Reliability Organization (RRO), as well as the Reliability Coordinator, approve protective relay settings. This determination should be made at the Regional Reliability Organization. |
| Response: Changes have been made to the standard and the standard now requires that the responsible entities obtain 'agreement' from the RC, TOP and PA' – the standard does not include the word, 'approve'. The RRO was removed as a responsible entity. If the RRO registers to be a PA (or PC) then the RRO will be performing this duty as the PA, not as the RRO. Moving forward, standards will not be written with requirements assigned to the RRO. | |
| Ameren (1)<br>Robert Rauschenbach | Introduction section:<br><br>4.1.2 Critical facilities between 100 kV and 200 kV need further definition. Each of the regions will interpret this differently. Perhaps facilities between 100 kV and 200 kV should not be included as critical until a clear definition is provided.<br><br>Requirements section: |

| Question #7 – Other comments on the standard? | |
|---|---|
| Commenter | Comment |
| | R1.3.1 and R1.3.2 The use of 0.85 per unit voltage for relay load limit is redundant. The maximum power transfer is calculated at 1.0 per unit. The 115% factor in R1.3 already provides margin.<br><br>R1.5 This doesn't make sense. How can the line carry a maximum load of 1.7 multiplied by the end of line 3-phase fault? This requirement should be removed.<br><br>R1.6 It is not clear how the 230% factor is derived. Is this 2.0 times the generation rating time a 1.15 multiplier? For parallel lines, how many contingencies should be considered? With 4 lines in parallel, would 3 lines be assumed out-of-service? This does not appear realistic. Further definition is needed. Justification for requirements beyond those shown in NERC's Table-1 should be provided.<br><br>R1.8 The term 'any system configuration' is ambiguous and confusing. It is not clear how many contingencies should be considered. As is R1.6, further definition is needed, and justification for requirements beyond those shown in NERC's Table-1 should be provided.<br><br>R1.9 It seems R1.7 is covered under R1.9.<br><br>R1.12 The necessity to cover remote lines under breaker failure conditions is not addressed. Remote breaker failure coverage is required on breaker-and-a-half, ring-bus, and in-line breaker applications. The 1.25 coverage of these breaker failure conditions should be included as an exception.<br><br>R1.12.3 There is already margin in the relay load limit calculation. There is no need for an additional restriction on the facility rating. This is operationally burdensome and confusing to carry two load limit numbers.<br><br>R2 R2.1, R2.2, and R2.3 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings. |

Response:
Introduction Section
4.1.2 – Only the Reliability Coordinator can determine which facilities are critical to reliability within the region. In some areas of North America, 138 kV, 161 kV, 230 kV, or other similar voltage class lines are very critical to the reliability of the BES, and need be considered. In other areas, with extensive higher-voltage transmission systems, these systems have the characteristic of high-voltage distribution lines.

Requirements Section

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| R1.3 – The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions. A 15% margin is needed beyond these two expected values.<br><br>R1.5- This is supplied to reflect the maximum power that can flow from a weak source terminal, based on the fault current source at that terminal. Detailed information is supplied in the reference document.<br><br>R1.6 – Yes – the 230% is 115% above 200%. As for the number of contingencies, it's as many as it takes to get to one line left, unless SPS's prevent operation of the generator for such conditions.<br><br>R1.8 – It is as many contingencies as it takes to get to one line left. Detailed information is supplied in the reference document.<br><br>R1.9 – While the requirements may seem similar, the requirements address different topology.<br><br>R1.12 – Requirement R1.12 is designed to provide a reduced facility rating based on minimum line protection. There are many ways to accomplish breaker-failure-protection beyond simple use of mho characteristic step distance relays. Such methods include use of direct-transfer-trip communications and use of relay characteristics (lens, load encroachment, etc) that permit enhanced relay loadability while still providing necessary protection.<br><br>R1.12.3 – R1.12.2 calculates the relay loadability based on the extreme conditions observed in past blackouts. R1.12.3 establishes the facility ratings by applying a 15% margin to account for relay and instrument transformer error consistent with the other criteria under R1.<br><br>R2 – These have a subtle difference, in that one asks for regional concurrence on the rating used, and the other establishes a new rating. These requirements have been modified in the new draft of the standard. | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | R1 Include the words "load carrying" in front of capability.<br>R1.1 Please confirm that the 150% margin that is added on top of the 0.85 p.u. voltage and 30 degree power factor angle is not too large. Would a margin of 125-130% be sufficient? This would have a tendency to provide an increased level of protection for the transmission system.<br>The voltage used to evaluate loadability at generating switchyard buses should not be lower than the value at which the plant auxiliary systems can be operated.<br>R1.11 This requirement is not clearly stated. Why is it referring to R1.10? R1.10 is for fault protection relays and R1.11 is for overload relays and they say virtually the same thing. The wording in R1.11 does not reflect the intent of the reference document. The reference document section similar to R1.11 allows for lower settings with supporting documentation. Therefore reference to R1.11 should be included in M2.<br>R1.12 Include the words "load carrying" in front of capability.<br>M2 What is meant by the terms circuit rating and facility rating? Do they need special definitions.<br>General : |

<table>
<tr><th colspan="2">Question #7 – Other comments on the standard?</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>Should this standard include definitions for several special terms used in this standard?<br>Consider a bi-annual review and self-certification or data submittal rather than an annual review.</td></tr>
<tr><td colspan="2">Response: R1 and R1.12 - Adding the words “load carrying” would be redundant with what is already stated.<br>R1.1 – The 150% is necessary to provide the system operator with adequate response time for extreme system conditions and also account for errors in the relaying system.<br>The generation aux power voltage may differ greatly from the transmission system voltage; the voltage referenced is difficult to quantify in a standard. If this is an issue in a specific example, R1.13 can be used.<br>R1.11 – R1.11 refers specifically to relays used for transformer overload protection and provides some additional flexibility to reflect the actual parameters affected by overloads.<br>M2 – Changes have been made to the Standard to clarify that the responsible entity’s facility rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator.<br>The SDT is not aware of any special terms that need to be defined.<br>Most stakeholders who responded seem to indicate support for an annual review.</td></tr>
<tr><td>Hydro One Networks Inc. (1, 3) – David Kiguel</td><td>Requirement R1: The phrase "The relay performance should be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should clearly state that the requirement applies only to RELAYS that are sensitive to voltage and/or power factor angle.<br>Requirement R1.1 remove the word "seasonal" that precedes "Facility Rating of a circuit."<br>Requirement R2 and Measure M2 make reference to requirement R.13 It should read R1.3 instead.<br>References to requirements in the documents use the full word (e.g. Requirement 1.12 in R2.20 or the abbreviation Rx.y (e.g. R1.6 in R2). We recommend consistency in the use of these references.</td></tr>
<tr><td colspan="2">Response: R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.1 – Facility Ratings may be specified on a seasonal basis. Therefore, the drafting team feels that it is important to emphasize that the highest of various seasonal Facility Ratings be used.<br>R2/M2 – Acknowledged.</td></tr>
<tr><td>IESO (2)<br>Ron Falsetti</td><td>Level 3 incorporates the clause: "… and the relay settings were causal to a Reportable Disturbance". We feel that improper or incorrect device settings or maintenance could lead eventually to that particular device being the cause of a disturbance or a reportable event. However, this should not be the basis for the violation. Linking a compliance level to a causal effect should not be part of a standard as this would render this particular standard inconsistent with the other standards.<br>We believe that the level orders are reversed for Level 3 and Level 4. Level 3 actually refers to "non-compliance" through the statement: "Relay settings do not comply…" whereas Level 4 is referring to "supporting evidence or documentation" through the statement: "Evidence does not exist…". From the language, it clearly seems to indicate that Level 3 is more stringent than Level 4.</td></tr>
</table>

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| | We feel that L 2.2.1 is incorrectly stated. In its present form, it states that "Evidence that relay settings comply with one of the criteria in R.1.1 through R1.13 exists but is incomplete or incorrect". This statement should be revised as "Evidence that relay settings comply with the criteria in R1.1 through R1.13 exists but is incomplete or incorrect for one or more of the requirements". |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| Entergy Services, Inc. (1)<br>Ed Davis | Level 3 and level 4 non-compliance criteria should be swapped since level 3 is a more severe "violation" than level 4. |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | Level three and four seem to be reversed. Level three is dealing with a relay that actually caused an event due to not meeting the Loadability Standard requirements, while level four deals with the documentation of a relay's compliance with the Loadability Standard. Also, if the two levels are reversed, should it matter how a relay is discovered to be in non-complance with the Loadability Standard? The new level four should read: Relay settings that do not comply with the loadability criteria in R1.<br>The last sentence of R1 is stated for distance relay evaluation. A method to evaluate other relays should be worked into this sentence. |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 – The drafting team feels that this evaluation is appropriate for all load-responsive relays. If voltage and/or power factor do not impact the performance of a specific relay technology, it should not be necessary to state that they do not need to be considered. | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | It seems that the Level 3 and Level 4 non-compliance are reversed in their severity and priority. Also, there are errors in R2 and M2; "Requirement 13" should be "R1.13", and please use a consistent approach to referencing other requirements - "Requirement" or "R". |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Typos acknowledged. | |
| SCE&G ERO Working Group<br>Sally Wofford | Requirements Section:<br>R1 Opening paragraph: "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor |

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| | angle of 30 degrees. Suggest that this sentence be clarified to state that it applies only to relays sensitive to voltage and/or power factor angle.<br>R1.2.1 and R1.3.2 Reference Document - The calculation of maximum power transfer at 1.0 per unit seems to be inconsistent with the use of 0.85 pu voltage for the relay load limit.<br>R1.5 Reference Document - More explanation is needed to avoid confusion.<br>R2 In the text of R2, R.13 should be R1.13. R2.1 and R2.2 appear to be easily combined.<br>Non-Compliance Levels<br>Suggest that non-compliance levels 3 & 4 be exchanged. It seems that non-compliance resulting in a reportable disturbance is more serious than ….evidence does not support…. |
| Response:<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.2.1 and R1.3.2 – The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – More explanation of your confusion is needed by the SDT to address your comment.<br>R2 - The text of R2 should have been R1.13 as indicated. This has been corrected.<br>R2.1 and R2.2 were modified and combined in support of your suggestion and other suggestions made by other stakeholders.<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish<br><br>MRO (2) et al<br>Joseph Knight | (1) Manitoba Hydro (MRO) has a concern with the 15% additional margin applied to the facility rating. This can be considered a negative margin worth protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy.<br><br>(2) Does this standard expose the TO etc. to legal risk if there is damage to the public (violating vertical clearances for example)<br><br>(3) If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems (not to mention the human involvement) designed and maintained with equivalent reliability to the protection system? Also, the SCADA system may be down therefore the operator may not be able to assume the role of preventing equipment damage. |

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| | (4) There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 pu voltage, and power factor angle of 30 degrees. criteria may not be appropriate for all cases.<br><br>(5) If you have too prescriptive a standard you may discourage people coming up with adaptive solutions.<br><br>(6) This standard removes the option of using zone three relays to provide more reliable system operation<br>(a) For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. (Moving blinders in may make it impossible to detect fast moving swings)<br><br>(b)On interties: It may not be possible to set relays to detect fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur.<br><br>(7) This standard seems to be precluding the concept of TO's etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system.<br><br>(8) R2.1 and R2.2 could be combined by adding 1.12 to the list in R2.1 and removing R2.2<br><br>(9) In M1 and M2 it should be further clarified what is meant by "evidence".<br><br>(10) In R2, why would it be necessary to get approval of the RRO and RC? If each criteria choice is valid, why is this necessary? This is unnecessary bureaucracy.<br><br>(11) Is the interpretation of R1 that the TO etc. could more that one criteria within their system?<br><br>(12) In Appendix A what is meant by: 1.2.3 Protection systems intended for protection during stable power swings?<br><br>(13) On page 6, R1.1.2, I in the formula for Zrelay30, should 1.5 be 1.1? |
| Response: (1) System protection systems are designed to remove faults. Typically, system protection criteria do not include preventing equipment damage from over load conditions. Operator action is required to protect facilities from overload conditions per NERC Standard TOP- | |

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| 008-0, R3. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond.<br>(2) Fault protective relays are not intended to prevent code violations.<br>(3) Fault protective relays are not intended to prevent thermal overloads.<br>(4) R1.13 permits such studies.<br>(5) There is ample opportunity for entities to develop adaptive solutions and still maintain loadability.<br>(6) The conditions you present may need protection expressly designed for those systems.<br>(7) R1.13 addresses the situation you present.<br>(8) R2.1 and R2.2 were modified and combined in support of your suggestion and other suggestions made by other stakeholders.<br>(9) The Standard can not be overly prescriptive in this area and can not impose additional requirements within the measures.<br>(10) Changes have been made to the standard.<br>(11) Yes. A Transmission Owner may use any criteria that is appropriate for each terminal.<br>(12) In some parts of North America (for example, in Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance relative to voltage, frequency, and power oscillations.<br>(13) The SDT is not certain to which formula you refer. We have reviewed formulas in Reference Document clauses R1.1 and R1.2 and all are correct. | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen<br><br>Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br><br>Requirements section:<br>Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.<br>R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.<br>R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion.<br>R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become |

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| | outaged is forseable (i.e. one line is out for maintenance and a fault occurs on the second line), applying this scenario to more multiples becomes more and more unlikely.<br>R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.<br>R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings. |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Requirements Section<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.31 and R1.3.2 - The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – The standard provides a concise statement of the requirement. For the basis of the requirement and supporting material, please see the reference document.<br>R1.6 – The conservative nature of this requirement is intentional. The probability is low but the impact is high.<br>R1.9 and R1.7 - While the requirements may seem similar, the requirements address different topology.<br>R2 - R2.1 and R2.2 were asking for slightly different things – they have modified and combined in support of suggestions made by other stakeholders. | |
| NERC System Protection and Control Task Force<br>Jon Sykes | Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br>Regarding R1 - The phrase "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle. For example, we suggest "Relay load-carrying capacity (in amperes) shall be evaluated at 0.85 per unit voltage and at a power factor angle of 30<br>degrees for relays sensitive to voltage and/or power factor angle, and shall be evaluated directly for overcurrent relays."<br><br>Regarding R1.10 - "Transformer protection relays and relays on transformer terminated lines shall be set so that they do not operate at or below the greater of:" |

<table>
<tr><th colspan="2">Question #7 – Other comments on the standard?</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>Editorial Comments - In R2 and M2, "Requirement 13" should be "R1.13". Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either "Requirement …" or R…"<br><br>Although we understand the reasoning behind tying Level 4 non-compliance to a reportable disturbance, it seems to be inappropriate to do so in this Standard. No requirement is established within the Standard that specifies that a non-compliance shall not contribute to a reportable disturbance. Standards set forth Requirements and Measures by which compliance with the requirements will be assessed. The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance. While I agree that causing a reportable disturbance is a significant concern, I feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance. Failure to comply with the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard. If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Compliance section of each and every Standard for which non-compliance could lead to a reportable disturbance. Establishing such penalties outside the Standards would ensure uniform treatment for all such events.</td></tr>
<tr><td colspan="2">Response:<br>The ‘levels of non-compliance’ were all replaced with ‘violation severity levels’ to conform to the ERO Rules of Compliance. While ‘levels of non-compliance’ were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Standards Section<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.10 - The standard was changed in support of your suggestion.<br>R2 and M2 - These clauses were changed extensively in the standard. In making these changes, the drafting team addressed the editorial comments that you noted.</td></tr>
<tr><td>So. Company Services, Inc. (1) – Jim Busbin</td><td>Southern Company Transmission supports the following portion of the comments made by the NERC System Protection and Control Task Force:<br>"Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than 'no evidence exists to support that relays comply with one of the criteria . . . .' The existing Level 3 should also be 'causal or contributory' instead of just 'causal'. It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay), whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by 'Evidence indicates that relay settings do not comply with R1.1 through R1.13' as a Level 4 non-compliance.</td></tr>
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| | Regarding R1 - The phrase 'The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees' should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle.<br>Editorial Comments - In R2 and M2, 'Requirement 13' should be 'R1.13'. Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either 'Requirement . . . ' or 'R . . . .'" |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 - The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R2 and M2 - These clauses were changed extensively in the standard. In making these changes, the drafting team addressed the editorial comments that you noted. | |
| National Grid (1)<br>Herb Schrayshuen | Section B -- Requirements<br>R1: The Standard should clarify that the protection system owner is free to select any of the criteria in R1.1 through R1.13 and need not apply the same one on all protection systems.<br>R11: The Standard should allow for overcurrent settings set below 150% of the maximum transformer nameplate rating or 115% of the highest operator established emergency transformer rating if the relays are supervised by a distance element that meets the relay loadability requirements.<br>R2: The reference to "R.13" should be "R1.13". The same error is repeated under Section C - Measures at M2 and under Section D - Compliance at 2.1.1.<br>R2.1 and R2.2: Given the identical wording in these two requirements it is not clear to the reader why these two requirements could not be combined. Additional text should be added to clarify that R2.1 pertains to criteria used to verify that the loading cannot be reasonably expected to exceed relay loadability, whereas R2.2 pertains to a criterion that establishes an equipment rating less than its actual capability based on the relay setting.<br>Section D -- Compliance<br>We do not agree with assigning different Levels of Non-Compliance depending on the method by which the non-compliance is identified. The draft Standard sets forth the Requirements and the Measures by which compliance with the requirements will be assessed. The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance. While we agree that causing a reportable disturbance is a significant concern, we feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance. Failure to comply with a Requirement in the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard. If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Standards. Establishing such penalties outside the Standards would ensure |

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| | uniform treatment for all such events. |
| Response: R1 – The phrase, "for any specific circuit terminal" was inserted to address your comment.<br>R1.11 – R1.11 Supervising (or better yet, torque controlling) an overcurrent relay with a distance relay that meets the requirements clearly results in a protective application that "allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater". This does not represent a requirement, but instead a method of meeting the requirement. The drafting team does not feel that this needs to be added to the standard.<br>R2 – Typos have been addressed.<br>R2.1 and R2.2 - These clauses were combined, as suggested.<br>Section D – We agree that no part of the standard specifies that an incorrect relay should not contribute to a reportable disturbance. The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| California ISO (2)<br>Brent Kingsford | R2, R2.1, R2.2, R2.3, and M2 list the Reliability Coordinators as an entity that is required to approve transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13. We disagree with the standard listing Reliability Coordinators as an entity that will approve relay settings when set according to the criteria above. We are concerned that Reliability Coordinators may not be staffed with relay engineers and obtaining approval from the Reliability Coordinators would be perceived as validation of a setting when that approval would really only be an acknowledgement of the setting criteria.<br>Reliability Coordinator should be deleted from the requirements and measures listed above. |
| Response: R2 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. | |
| PJM Reliability Services Division – Al DiCaprio (2) | Level 2 needs to be reworded. Level 2 implies "that evidence of COMPLIANCE exists" then states that the evidence is incomplete. Either it is compliant or it is incomplete.<br>The Level 3 and Level 4 non compliance seems to be reversed. Level 3 seems to be related to a more adverse result than does Level 4.<br>Reliability Coordinators are responsible for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The verification of relay settings is more appropriate at the Transmission Operator level. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Paragraph 3 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. | |
| ISO/RTO Council | The IRC (AESO) favors standards that define performance requirements and measure compliance based on |

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| Charles Yeung<br><br>AESO (2)<br>Anita Lee | that performance. The IRC (AESO) questions the incorporation of difference Levels of Compliance based on the cause of the given performance.<br>NERC already has a process that includes Violation Risk Factors and Violation Severity Levels to 'adjust' non-compliance penalties. To include another subjective adjustment factor would seem to be inappropriate.<br>The IRC (AESO) suggests that the SDT consider reversing the level orders for Level 3 and Level 4. From the language in the standard, the current Level 3 is more stringent than Level 4.<br>The IRC (AESO) does not agree that the Reliability Coordinators should be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The IRC notes that not all RCs have appropriate expertise in making such determinations and therefore suggests that the verification of relay settings is more appropriate at the Transmission Operator level. Further the Functional Model White Paper does not include any relay setting or authorization responsibilities for the RC. |
| Response:<br>We agree that no part of the standard specifies that an incorrect relay should not contribute to a reportable disturbance.<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Paragraph 4 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. | |
| New York ISO (2)<br>Michael Calimano | The NYISO also supports the IRC comment that the Reliability Coordinators should not be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2).<br>Also, guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document. |
| Response: "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. Appendix D was added to the Reference Document to address SOTF. | |
| FRCC (2)<br>Eric Senkowicz | Section 2.3 and 2.4 should be swapped with regards to Levels of Non-Compliance. A mis-applied setting that was causal to a Reportable Disturbance appears to be the worst-case infraction and therefore should be the "Level 4" Non-compliance.<br>Has the drafting team considered the concept of "temporary exceptions" to the setting criteria? One of the concerns expressed in our Region is that during certain system modifications, (i.e. new lines, configuration changes, ampacity upgrades, etc) it may be necessary to deviate from the prescribed criteria on a temporary basis, so that the necessary relaying modifications may be made to accommodate the system changes? This type of "temporary exception" would allow construction implementation without racking up a violation, and still maintaining adequate equipment protection.<br>Lastly, has the drafting team considered adding a "grace" period for resolving self-identified non-compliances |

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| | to the setting requirements of this standard? As an example a "non-compliant" setting that is self-identified would be reportable but would not result in a non-compliance violation if the settings were corrected within a certain time period.<br>We appreciate the team's rigorous efforts at creating this complex standard and also appreciate the opportunity to provide the above comments. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>As for the question about "temporary exceptions" for in-progress system modifications - the standards to not provide a mechanism for non-compliance without resulting in a violation. The drafting team recommends that one of the other requirements be used to establish reduced facility ratings during such a period. For example, R1.13 establishes that the equipment owner may develop study based ratings for relay loadability applications and that those ratings become reflected in the facility ratings. Another approach to this issue would be to apply R1.12, again with full acceptance of the resulting reduced ratings.<br>Paragraph 3 – While there is no specified grace period, the penalties and sanctions calculator already incorporates reductions in fines and penalties if an entity self reports promptly and takes immediate corrective action. We believe this addresses your concern. | |
| AECI (1)<br>John F. Bussman | See SERC comments for the Level of non compliance section comments.<br>In R1. We are not sure of the basis for the .85pu voltage and 30 degrees phase angle.<br>R1.3.1 Agree with the SERC comment of the inconsistency of .85 vs 1.0 pu.<br>Agree with SERC comments regarding R1.6 R1.9 and R2<br>R1.5 We are concerned on how the transmission line being fed from a "weak source" can be protected if the line relays are set to not operate at or below 170% of the maximum end-of-line three-phase fault magnitude. It would seem that if a fault condition did exist at the end of the line, the relay would not clear this fault and would just serve it as load. More clarification is required regarding this setting<br>How does this standard apply to tapped lines that are greater than 200KV when the relays are set to trip the tapped line however not the main feeder line. |
| Response: See Response to SERC comments.<br>R1 - The industry actions relate relay loadability to system collapse. Therefore the use of 0.85 pu voltage and a 30 degree phase angle for relay performance calculations is appropriate. Studies into the various WECC collapses, into the 1967 blackout, and into August 2003 show that the system voltage becomes depressed and a 30 degree power factor angle is very common during the pre-collapse time periods, and it is these time periods during which the evaluation of the relay performance is most critical. These conditions were found to be typical under these conditions and by no means reflect worst case conditions.<br>R1.3.1 & R1.6 & R1.9 & R2 – See response to SERC comment.<br>R1.5 – A distance relay will operate for these conditions. Refer to the reference document for additional details.<br>Last comment – The standard applies to all terminals whether tapped or not. Different optional criteria from among the requirements may be | |

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| useful for tapped terminals. | |
| SPP (2)<br>Makarand Nagle | NERC should provide, as a part of the standard, the loadability verification spreadsheet(s) and technical exceptions documentation it wants for documentation purposes. There may be many differing opinions on what documentation is acceptable. However, NERC should have created forms/spreadsheets/papers for completion that satisfy their documentation for loadability requirements.<br>Although SPP agrees with the need for a protection loadability standard, we believe this standard should apply to only 345kV and above systems. Most companies with 345kV and above have a larger impact on wide area/multi-state blackouts. Although the 100 to 200 kV systems may be critical to a localized region, loss of those voltages will probably not spread into a multi-state blackout, provided the 345kV and above systems remain in service. There are other regional requirements for loading and line ratings that probably suffice for the localized regions. |
| Response: (1) The SDT does not want to be overly prescriptive in specifying entity documentation.<br>(2) In some areas of North America, 138 kV, 161 kV, 230 kV, or other similar voltage class lines are very critical to the reliability of the BES, and need be considered. In other areas, with extensive higher-voltage transmission systems, these systems have the characteristic of high-voltage distribution lines. | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | See SPCTF comments. |
| Response: See response to SPCTF comments. | |
| Minnkota Power Coop, Inc. (1, 3, 5) – Tim Bartel | Using this one-size-fits-all approach for out-of-step blocking / tripping relays would prevent proper application in some situations. Orderly system separation following major events may require higher impedance out-of-step blinder settings than would be allowed by the standard.<br><br>Perhaps this is allowed for by the reference to "stable power swings" in section 1.2.3 of Attachment A, but it is not clear if this is the case. |
| Response: Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. However, when the out of step tripping or blocking relays are a part of a Special Protection Scheme (SPS), the SPS should be reviewed per the applicable NERC standards. | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | Hydro-Québec TransÉnergie (HQTÉ) is concerned about the Applicability of the standard (section A 4.1). It appears the standard applies to elements based solely on their voltage level.<br>It should be clarified that the standard applies only to BPS equipments. As a member of NPCC, HQTÉ have been using a performance based criteria to determine such equipments rather than using the voltage level.<br>HQTÉ has also an issue about some specific application of the standard.<br>In particular, for a portion of our 315 kV system, the standard as written cannot be complied with for technical reasons due to the system characteristics. We had to apply for technical exception. |

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| **Commenter** | **Comment** |
| | Also, in relation to the hot spot winding protection for all 735 kV transformers, HQTÉ practice for overloading those transformers imposes additional safety margins than what is proposed in IEEE C57.91 -1995. Again, HQTÉ will have to apply for technical exception.<br><br>These technical exceptions will not affect the reliability of the system.<br><br>The standard should be less specific to allow for such technical conditions. If technical exceptions are permitted, this should be indicated in the standard.<br><br>HQTÉ suggest the addition of two more elements in item 1.2 of Attachment A:<br>1) Relay elements associated with DC lines<br>2) Relay elements associated with transformers at converter station. |
| Response: The facilities to which the standard applies were selected to be consistent with the previous relay loadability activities within NERC. The technical exceptions available under the previous activities have been restated within the standard as criteria for demonstrating compliance. If none of these specific criteria apply, then R1.13 is available to establish study based compliance.<br>The suggested elements were added to Attachment A | |
| SERC PCS<br>Susan Morris | Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br><br>Requirements section:<br>Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.<br><br>R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.<br><br>R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion. |

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| | R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become outaged is foreseeable (i.e. one line is out for maintenance and a fault occurs on the second line), applying this scenario to more multiples becomes more and more unlikely.<br><br>R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.<br><br>R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 - The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered. R1.31 and R1.3.2 - The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – The standard provides a concise statement of the requirement. For the basis of the requirement and supporting material, please see the reference document.<br>R1.6 – The conservative nature of this requirement is intentional. The probability is low but the impact is high.<br>R1.9 and R1.7 - While the requirements may seem similar, the requirements address different topology.<br>R2 - "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. R2.1 and R2.2 were combined. | |

## Attachment 1 – Supplementary Comments

## Comments on NERC Line Loadability Standard PRC-023 Reference

Most WECC members are well aware of the problem of setting zone 2 or zone 3 distance relays on long transmission lines with enough reach to adequately protect the line without violating NERC recommendation 8A. The problem arises because the thermal current limit of a line is independent of the lines length and does not change for a given conductor size no matter how long it is. The impedance of the line, however, increases with the lines length. As the line length and impedance increases, the reach of the distance relays that protect the line must also increase to provide adequate protection, until at some point the relay setting would operate for the maximum thermal current. This creates the dilemma of how to protect such a long line without limiting its load carrying ability.

On the other hand, as the line length and impedance increases, the ability to transfer power across the line diminishes until a point is reached where the maximum possible power transfer is less than the rated thermal power transfer limit. Using this diminished power transfer capability instead of the thermal limit as the basis of setting the reach of the distance relays should allow for a longer relay reach that will hopefully provide adequate protection for the line.

Requirements R1.3.1 and R1.3.2 of NERC Standard PRC-023-1, and as detailed in the *PRC-023 Reference*, attempt to allow the use of the maximum power transfer capability of a line to justify the use of relay settings that will operate at loads less than the line's thermal rating. While this approach has merit, I have the following concerns:

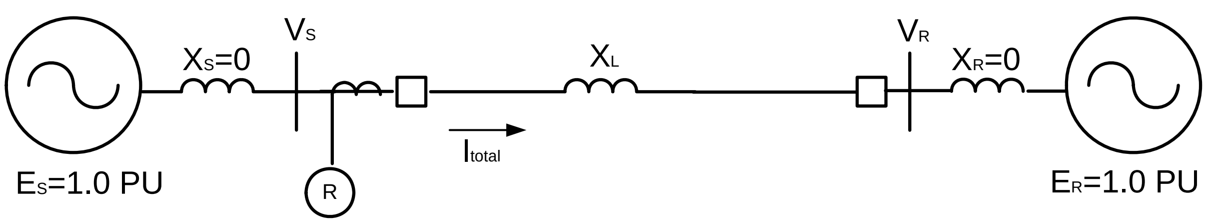
1) R1.3.1, correctly applied, will not justify a mho characteristic relay reach at the line impedance angle greater than 100% of the line impedance, and therefore, is not useful.

2) R1.3.2 offers little improvement over R1.3.1 and is not likely to justify the necessary reaches of zone 2 or 3 relays on very long lines.

3) The impedance seen by a relay is a constant percentage of the line impedance for any given power angle. This can be used to determine the maximum acceptable relay reach for any power angle. This may be useful to justify practical limits for relay reach.

Following is my explanation of the above concerns.

### 1) R1.3.1 Does Not Justify Relay Reaches Greater Than 100% of the Line Impedance




R1.3.1 attempts to determine a relay reach based on the maximum theoretical power flow across a line that occurs when the power angle, δ, is 90°.

From R1.3.1 of the *PRC-023 Reference*, page 4:

$I_{total} = (V_{LL}\sqrt{2})/(X_L\sqrt{3})$

The impedance seen by the relay is:

$Z_R = V_{LG}/I_{total}$ where $V_{LG}$ is the line-to-ground voltage and $V_{LG} = V_{LL}/\sqrt{3}$ under balanced load

$Z_R = (V_{LL}/\sqrt{3}) / [(V_{LL}\sqrt{2})/(X_L\sqrt{3})]$

$Z_R = X_L/\sqrt{2}$

So the impedance seen by the relay, $Z_R$, is independent of the bus voltage during a maximum power transfer condition. If the voltage sags, the maximum possible power transfer across the line will also drop, and the impedance seen by the relay will remain constant.

Under the conditions assumed in R1.3.1, $|V_S| = |V_R|$ and the angle between $V_S$ and $V_R$ (power angle, δ) is 90°, the current through the line, $\mathbf{I}_{total}$ will lag the voltage at the sending end by 45°, and the impedance seen by the relay, $Z_R$ , will be at 45°. Converting this to the maximum allowable reach for a mho characteristic relay at the line angle of 90° gives:

$Z_{90} = Z_R / \cos(90°-45°) = (X_L/\sqrt{2}) / \cos 45° = X_L$

The result shows that for a mho characteristic distance relay, the maximum power transfer approach will never justify setting the reach of a mho characteristic beyond 100% of the line impedance. Stated another way, at the maximum theoretical power transfer, a mho-characteristic distance relay with a reach equal to 100% of the line impedance at a maximum torque angle of 90° will pick up on load.

The results derived in R1.3.1 are slightly different because two safety factors are introduced. The first a voltage factor of 0.85 isn't necessary because, as shown above, the impedance seen by the relay is unaffected by the voltage when the maximum power transfer approach is used. The second safety factor increases the current by 1.15 which results in a reduced allowable relay reach of 1/1.15 or 87%.

Even with the safety factors, the impedance allowed by R1.3.1 is still larger than the value derived above ($Z_{90} = X_L$) because R1.3.1 incorrectly recommends that the impedance derived from the maximum power transfer equation be applied at a power factor angle of 30° instead of 45°. From R1.3.1:

$Z_{relay30} = (0.85V_{LL}) / (1.15 \cdot \mathbf{I}_{total}\sqrt{3}) = (0.85/1.15)(V_{LL} \cdot X_L\sqrt{3})/(V_{LL}\sqrt{2}\sqrt{3})$

$Z_{relay30} = (0.85/1.15)(X_L /\sqrt{2}) = 0.739X_L/\sqrt{2}$

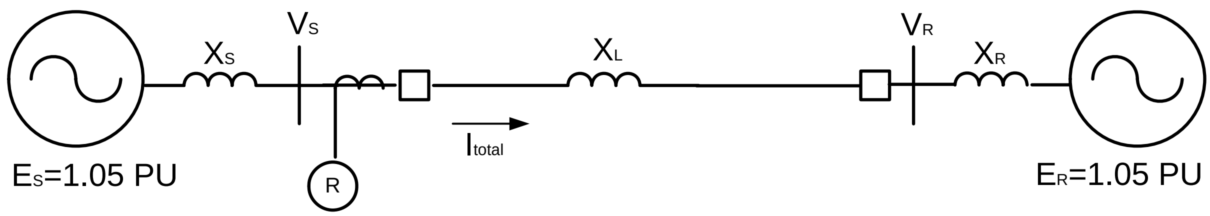
The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°-30°) = (0.739X_L/\sqrt{2}) / \cos 60°$

$Z_{90} = 1.045 \cdot X_L$

So, the use of a 30° power factor angle as recommended in R1.3.1 offsets the safety margins that were applied and allows a slightly longer distance relay reach of 104.5% of the line impedance. This is not enough reach for a zone 2 relay to provide adequate protection for the line. The maximum power transfer approach, as used in R1.3.1, is useless in justifying adequate zone 2 settings for long lines!

**2) R1.3.2 Offers Little Help Over R1.3.1**




R1.3.2 uses the source impedances of the system to obtain a reduced maximum theoretical power flow at the power angle, δ, of 90°, and therefore a longer allowable relay reach than obtained by R1.3.1

From R1.3.2 of the *PRC-023 Reference*, page 6:

$I_{total} = (1.05V_{LL}\sqrt{2}) / [(X_S + X_R + X_L)\sqrt{3}]$

$Z_{relay30} = (0.85V_{LL}) / (1.15\cdot I_{total}\sqrt{3}) = (1/1.05)(0.85/1.15)(X_S + X_R + X_L)/\sqrt{2} = 0.498(X_S + X_R + X_L)$

This is the same impedance seen by the relay as derived in R1.3.1 with $X_L$ replaced by $(X_S + X_R + X_L)$ and the result divided by 1.05 because of the 1.05 P.U. source voltage used.

The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°-30°) = 0.498(X_S + X_R + X_L) / \cos 60°$

$Z_{90} = 0.996(X_S + X_R + X_L)$

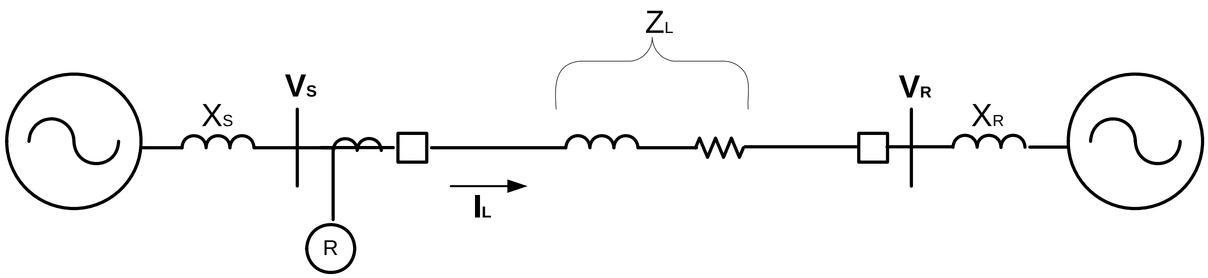
This shows that the maximum allowable reach of a mho characteristic relay at the line angle is approximately equal to $(X_S + X_R + X_L)$. This method will only allow a mho characteristic relay to overreach the line impedance by the same percentage that $X_s + X_R$ is to the line impedance $X_L$.

$Z_{90} = 0.996\cdot X_L\ [1+ (X_R + X_S)/X_L]$

In order to justify setting a zone 2 relay at the standard 125% of the line impedance with this method, $X_S + X_R$ must equal 25% of $X_L$. For many long lines the source impedance at the terminals will not equal 25% of the line impedance and this method will not justify a mho characteristic reach that provides adequate line protection.

As in R1.3.1, R1.3.2 applies the relay reach at a power factor angle of 30° instead of the correct angle of 45°. Using 45° results in even less allowable relay reach.

### 3) Another Approach




From the above diagram where $\mathbf{V_S}$ is the phase-to-ground voltage at the sending end, and $\mathbf{V_R}$ is the phase-to-ground voltage at the receiving end:

$\mathbf{V_S} = V_S\angle\Theta_S$ and $\mathbf{V_R} = V_R\angle\Theta_R$

$\mathbf{I_L} = (V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L$

The impedance seen by the relay, $Z_R$, is:

$Z_R = \mathbf{V_S} / \mathbf{I_L} = V_S\angle\Theta_S / [(V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L]$

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S - V_R\angle\Theta_R)$

If the receiving end voltage is used as the reference, $\Theta_R = 0°$ and the power angle $\delta = \Theta_S - \Theta_R = \Theta_S$. If the magnitude of the sending- and receiving-end voltages are equal, $V_R = V_S$, and we get:

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S - V_S\angle 0°)$

$Z_R = Z_L \cdot V_S\angle(\Theta_S+\Theta_L) / V_S(1\angle\Theta_S - 1)$

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) / (1\angle\Theta_S - 1)$

This shows that the impedance seen by the relay, $Z_R$, is dependent only on the difference in angles between the sending and receiving end voltages and the magnitude and angle of the line impedance. The following table shows some values of $Z_R$ for different values of $\Theta_S$ when the line impedance angle, $\Theta_L$ , is 90°. The far right column shows the corresponding relay reach at 90° for a mho characteristic distance relay ($Z_{R90} = Z_R/\cos[90° - \Theta_{ZR}]$).

| $\Theta_S$ | $Z_R$ | Relay reach at line angle of 90° |
|---|---|---|
| 90° | $(0.707\angle 45°)\cdot Z_L$ | $1.0\cdot Z_L$ |
| 85° | $(0.740\angle 42.5°)\cdot Z_L$ | $1.095\cdot Z_L$ |
| 80° | $(0.778\angle 40°)\cdot Z_L$ | $1.210\cdot Z_L$ |
| 75° | $(0.821\angle 37.5°)\cdot Z_L$ | $1.349\cdot Z_L$ |
| 70° | $(0.872\angle 35°)\cdot Z_L$ | $1.520\cdot Z_L$ |
| 65° | $(0.931\angle 32.5°)\cdot Z_L$ | $1.732\cdot Z_L$ |
| 60° | $(1.00\angle 30°)\cdot Z_L$ | $2.00\cdot Z_L$ |

The table shows that in order to get a useful zone 2 reach of 125% or more of the line impedance, the power angle must be less than about 78°.

If the line impedance angle, $\Theta_L$ , is different than 90°, the allowable relay reach at the line angle will still be the same as that shown for a line angle of 90° in the table above. For example, the allowable relay reach for a line impedance angle of 80° on a system operating at a power angle of 75° gives:

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) / (1\angle\Theta_S - 1)$

$Z_R = Z_L \cdot 1\angle(75°+80°) / (1\angle 75° - 1)$

$Z_R = Z_L \cdot (0.821\angle 27.5°)$

The allowable relay reach at the line angle of 80° is:

$Z_{R80} = Z_L \cdot 0.821 / \cos(80°\text{-}27.5°)$

$Z_{R80} = 1.349 \cdot Z_L$

This is the same reach as the one in the table above for a power angle of 75°. This example can be applied to any line and power angle, and the above table can be generalized to:

| Power Angle δ | Mho Characteristic Relay Reach at Line Angle |
|---|---|
| 90° | $1.0 \cdot Z_L$ |
| 85° | $1.095 \cdot Z_L$ |
| 80° | $1.210 \cdot Z_L$ |
| 75° | $1.349 \cdot Z_L$ |
| 70° | $1.520 \cdot Z_L$ |
| 65° | $1.732 \cdot Z_L$ |
| 60° | $2.00 \cdot Z_L$ |

If we wanted to set a mho characteristic relay to reach 130% of the line impedance at the line angle ($Z_{LA}$) and allowed for a 15% overreach error, we'd have

$Z_{LA} = (1.15)(1.30)\ Z_L = 1.495 \cdot Z_L$

From the above table, the relay would not pick up on load until the power angle across the line exceeded 70°.

**Summary**

Trying to justify zone 2 and zone 3 relay reaches on long lines using the maximum power transfer capability of the line as described in R1.3.1 doesn't work. The method described in R1.3.2 will be very limited in its usefulness. A more useful approach would be to select a practical power angle less than 90° that is not exceeded during stable power system operation and base the maximum relay reach on that. Can a power angle of less than 90° be accepted as a practical limit that is unlikely to be exceeded in real-life operation? If so, a maximum relay reach, as a percentage of line impedance at the line angle, should be allowed for mho characteristic relays without further restrictions or justification. For example, if a 70° power angle is acceptable as a limit that is unlikely to be exceeded in stable operation, a relay reach at the line angle of 130% of the line impedance could be allowed without further restriction or justification. This could greatly reduce the number of relay settings requiring an exception to the standard.

**Response:**
While the cited requirements may be of minimal use for mho characteristic relays they have proven to be useful for other characteristic shapes.
The SPCTF, when developing the earlier activities, explored various power transfer angles for use within the requirements and discovered actual situations where the power transfer angles exceeded 80 degrees.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC approves SAR for posting on January 9, 2006.
2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
3. The SAC approves development of the standard on May 12, 2006.
4. The JIC assigns development of the standard to NERC on June 15, 2006.
5. Drafting team post first draft for comments (August 16–September 29, 2006).

**Description of Current Draft:**

~~This is a 45-day (August 16 September 29) posting of the initial draft of the Transmission Relay Loadability Standard. It codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S. Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.*~~

The drafting team considered the comments on the initial ballot and has posted its consideration of those comments and made conforming changes to the implementation plan. The drafting team also made conforming changes to bring the standard into compliance with the Reliability Standards Development Procedure, Version 6. The drafting team is posting the revised standards and implementation plan for a 30-day comment period from January 9–February 9, 2007.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. ~~Consider and post response to comments.~~ Post for 30-day comment period. | ~~October 16, 2006~~January 9, 2007 |
| 2. ~~Post for 30-day comment period.~~Review comments from industry posting; post consideration of comments. | ~~October 16 November 14, 2006~~February 22, 2007 |
| 3. Post for 30-day pre-ballot period. | ~~November 20 December 19, 2006~~March 1–March 30, 2007 |
| 4. Conduct first ballot. | ~~December 20, 2006 January 3, 2006~~April 2–April 11, 2007 |
| 5. Consider and post response to comments on first ballot. | ~~January~~ April 18, 2007 |
| 6. Conduct second ballot. | ~~January 9~~ April 18–27, 2007 |
| 7. ~~BOT Adoption.~~BOT adoption date. | ~~February 1~~May 2, 2007 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability.

4. **Applicability:**

**4.1.** Transmission Owners with phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the ~~Regional~~ Reliability ~~Organization~~Coordinator as critical to the reliability of the ~~electric system~~Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the ~~Regional~~ Reliability ~~Organization~~Coordinator as critical to the reliability of the ~~electric system~~Bulk Electric System.

**4.2.** Generator Owners with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4~~:~~.

**4.4.** ~~**(Proposed)**~~ Reliability Coordinators.

5. **Effective Dates**[1]**:**

**5.1.** Requirement 1, Requirement 2, Requirement 4:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above — ~~July 1, 2008~~at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

**5.2.** Requirement 3: 18 months following applicable regulatory approvals.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system ~~**capability**~~loadability while maintaining reliable protection of the ~~**electrical network**~~Bulk Electric System for all fault conditions. ~~**The**~~Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay ~~**performance shall be evaluated**~~loadability at 0.85 per unit voltage and a

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15~~-~~-minute Facility Rating of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit ~~**bus**~~ voltage ~~**at**~~behind each ~~**end of the line**~~source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes~~)~~[2]~~.~~).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

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[2] ~~This requirement is based on a distance relay maximum torque angle (and thus the impedance angle) approaching 90 degrees, while the relevant load current angle is 30 degrees. In addition, if there is a weak source "behind" the relay, the fault magnitude in amperes may be limited while the distance to a fault, as measured by a distance relay, is not.~~

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature.

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

~~**R2. The Transmission Owner, Generator Owner, or Distribution Provider shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator(s) prior to using the criteria established in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 as listed below. The approvals are required for each circuit terminal using the listed criteria. [Risk Factor: Lower]**~~

~~**R2.1. The Transmission Owner, Generator Owner, or Distribution Provider that uses the criteria described in R1.6, R1.7, R1.8, or R1.9 shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator prior to using these criteria.**~~

~~**R2.2. The Transmission Owner, Generator Owner, or Distribution Provider that uses the criteria described in Requirement 1.12, shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator prior to using this criteria.**~~

~~**R2.3. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in Requirement 1.13, shall obtain the approval of the Regional Reliability Organization and the Reliability Coordinator before using the circuit**~~

~~**capability and shall use the circuit capability as the Facility Rating of the circuit.**~~

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Authority, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

**R3.** The Reliability Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

**R3.1.** The Reliability Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System

**R3.1.1.** This process shall include coordination with adjoining Reliability Coordinator(s).

**R3.2.** The Reliability Coordinator shall maintain a current list of facilities determined according to the process described in R3.1

**R3.3.** The Reliability Coordinator shall provide a list of facilities to its Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Reliability Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Reliability Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R~~**equirement**~~ 1.1 through R1.13. (R1 and R4)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the ~~**use of the criteria**~~ resulting Facility Rating was ~~**approved**~~agreed to by its associated ~~**Regional Reliability Organization**~~Planning Authority, Transmission Operator, and Reliability Coordinator ~~**before being used and shall have evidence that the circuit rating is used as the Facility Rating of that circuit.**~~. (R2)

**M3.** The Reliability Coordinator shall have a documented process for the determination of facilities as described in R3. The Reliability Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Transmission Operators, Generator Operators, and Distribution Providers.

## D. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

**1.1.1** ~~Regional~~Electric Reliability Organization.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Reliability Coordinator shall retain documentation of the most recent review process required in R3. The Reliability Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Reliability Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

~~2. Levels of Non-Compliance~~

**2. ~~Level 1:~~Violation Severity Levels: Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:**

**2.1.1** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that ~~approval~~agreement was obtained in accordance with R2.

**2.2. ~~Level 2:~~Moderate:**

**2.2.1** Evidence that relay settings comply with ~~one of the~~ criteria in R1.1 ~~through R~~though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. ~~Level 3:~~High:**

**2.3.1** NA

**2.4. Severe:**

~~2.3.1~~ Relay settings do not comply with ~~transmission loadability criteria in R1, and the relay settings were causal to a Reportable Disturbance.~~

~~2.4. Level 4:~~

**2.4.1** ~~Evidence~~R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels: Reliability Coordinator**

**3.1. Lower:**

**3.1.1** N/A

**3.2. Moderate:**

**3.2.1** N/A

**3.3. High:**

3.3.1 Reliability Coordinator does not provide the list to the appropriate Transmission Owners, Generator Owners, and Distribution Providers.

3.4. **Severe:**

3.4.1 Reliability Coordinator does not have a process in place to determine facilities that are critical to the reliability of the electric system.

3.4.2 Reliability Coordinator does not maintain a current list of facilities critical to the electric system,

## E. Regional Differences

1. None

## F. Associated Documents

1. PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Attachment A

~~1.1.~~1. This standard ~~addresses~~includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance

**1.2.** Out-of-step tripping

~~**1.1.3** Out-of-step blocking~~

**1.3.** Switch-on-to-fault

**1.4.** Overcurrent relays

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT)

**1.5.2** Permissive under-reach transfer trip (PUTT)

**1.5.3** Directional comparison blocking (DCB)

**1.5.4** Directional comparison unblocking (DCUB)

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Relay elements associated with DC lines

**3.8.** Relay elements associated with DC converter transformers.

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

1. SAC approves SAR for posting on January 9, 2006.
2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
3. The SAC approves development of the standard on May 12, 2006.
4. The JIC assigns development of the standard to NERC on June 15, 2006.
5. Drafting team post first draft for comments (August 16–September 29, 2006).

**Description of Current Draft:**

The drafting team considered the comments on the initial ballot and has posted its consideration of those comments and made conforming changes to the implementation plan. The drafting team also made conforming changes to bring the standard into compliance with the Reliability Standards Development Procedure, Version 6. The drafting team is posting the revised standards and implementation plan for a 30-day comment period from January 9–February 9, 2007.

**Future Development Plan:**

| Anticipated Actions | Anticipated Date |
|---|---|
| 1. Post for 30-day comment period. | January 9, 2007 |
| 2. Review comments from industry posting; post consideration of comments. | February 22, 2007 |
| 3. Post for 30-day pre-ballot period. | March 1–March 30, 2007 |
| 4. Conduct first ballot. | April 2–April 11, 2007 |
| 5. Consider and post response to comments on first ballot. | April 18, 2007 |
| 6. Conduct second ballot. | April 18–27, 2007 |
| 7. BOT adoption date. | May 2, 2007 |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability.

4. **Applicability:**

   **4.1.** Transmission Owners with phase protection systems as described in Attachment A, applied to facilities defined below:

   **4.1.1** Transmission lines operated at 200 kV and above.

   **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Reliability Coordinator as critical to the reliability of the Bulk Electric System.

   **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

   **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Reliability Coordinator as critical to the reliability of the Bulk Electric System.

   **4.2.** Generator Owners with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4.

   **4.3.** Distribution Providers with phase protection systems as described in Attachment A, applied according to 4.1.1 through 4.1.4.

   **4.4.** Reliability Coordinators.

5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2, Requirement 4:

   **5.1.1** For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.

   **5.1.2** For circuits described in 4.1.2 and 4.1.4 above — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   **5.2.** Requirement 3: 18 months following applicable regulatory approvals.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.

- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature.

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Authority, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

**R3.** The Reliability Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

**R3.1.** The Reliability Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System

**R3.1.1.** This process shall include coordination with adjoining Reliability Coordinator(s).

**R3.2.** The Reliability Coordinator shall maintain a current list of facilities determined according to the process described in R3.1

**R3.3.** The Reliability Coordinator shall provide a list of facilities to its Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Reliability Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Reliability Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Mitigation Time Horizon: Long Term Planning]

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1 and R4)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Reliability Coordinator shall have a documented process for the determination of facilities as described in R3. The Reliability Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Transmission Operators, Generator Operators, and Distribution Providers.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

**1.1.1** Electric Reliability Organization.

#### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

#### 1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Reliability Coordinator shall retain documentation of the most recent review process required in R3. The Reliability Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

#### 1.4. Additional Compliance Information

The Transmission Owner, Generator Owner, Reliability Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

### 2. Violation Severity Levels: Transmission Owner, Generator Owner, and Distribution Provider

#### 2.1. Lower:

**2.1.1** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

#### 2.2. Moderate:

**2.2.1** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:**

**2.3.1** NA

**2.4. Severe:**

**2.4.1** Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels: Reliability Coordinator**

**3.1. Lower:**

**3.1.1** N/A

**3.2. Moderate:**

**3.2.1** N/A

**3.3. High:**

**3.3.1** Reliability Coordinator does not provide the list to the appropriate Transmission Owners, Generator Owners, and Distribution Providers.

**3.4. Severe:**

**3.4.1** Reliability Coordinator does not have a process in place to determine facilities that are critical to the reliability of the electric system.

**3.4.2** Reliability Coordinator does not maintain a current list of facilities critical to the electric system,

## E. Regional Differences

**1.** None

## F. Associated Documents

**1.** PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance

**1.2.** Out-of-step tripping

**1.3.** Switch-on-to-fault

**1.4.** Overcurrent relays

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT)

**1.5.2** Permissive under-reach transfer trip (PUTT)

**1.5.3** Directional comparison blocking (DCB)

**1.5.4** Directional comparison unblocking (DCUB)

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Relay elements associated with DC lines

**3.8.** Relay elements associated with DC converter transformers.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Maureen E. Long**
Standards Process Manager

January 9, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

**Announcement: Comment Period Opens for Transmission Relay Loadability Standard; Nomination Period Opens for IROL Standard Drafting Team**

**The Standards Committee (SC) announces the following standards actions:**

## Transmission Relay Loadability Standard (January 9–February 7, 2007)

The Transmission Relay Loadability Standard Drafting Team posted the second draft of its standard for a 30-day comment period from January 9 through February 7, 2007. This standard codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and Wider Use of System Protection Measures.* Please use the comment form to provide comments on this standard.

## Nominations for Operate within Interconnection Reliability Operating Limits Standard Drafting Team (January 9–19, 2007)

The Standards Committee is seeking additional industry experts to serve on the existing Operate within Interconnection Reliability Operating Limits (IROLs) Standard Drafting Team. This set of standards addresses the Reliability Coordinator's preparations and actions relative to IROLs. If you are interested in serving on this team, please complete this nomination form and return it to Richard Schneider (Richard.schneider@nerc.net) no later than January 19, 2007.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply:
  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2, Requirement 4:
  - For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
  - For circuits described in 4.1.2 and 4.1.4 above — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.
- Requirement 3: Eighteen months following applicable regulatory approvals

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

~~The proposed standard will become effective on:~~

- ~~January 1, 2008 for transmission lines operated at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.~~
- ~~July 1, 2008 for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, as designated by the regional reliability organization as critical to the reliability of the electric system in the region.~~

Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply:
  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2, Requirement 4:
  - For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
  - For circuits described in 4.1.2 and 4.1.4 above — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.
- Requirement 3: Eighteen months following applicable regulatory approvals

# PRC-023 Reference

# Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Corporation

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

***Version 1.0***

***January 9, 2007***



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# Table of Contents

# Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Protection systems intended for protection during stable power swings
   - 2.4. Generator protection relays that are susceptible to load
   - 2.5. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017. Protection systems that are

designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

2.6. Relay elements associated with DC lines

2.7. Relay elements associated with DC converter transformers

# Requirements Reference Material

## R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

## R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L\text{-}L}$ = Rated line-to-line voltage

$I_{rating}$ = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating ($I_{rating}$) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

## R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been

determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating ($I_{rating}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

## R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

### R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

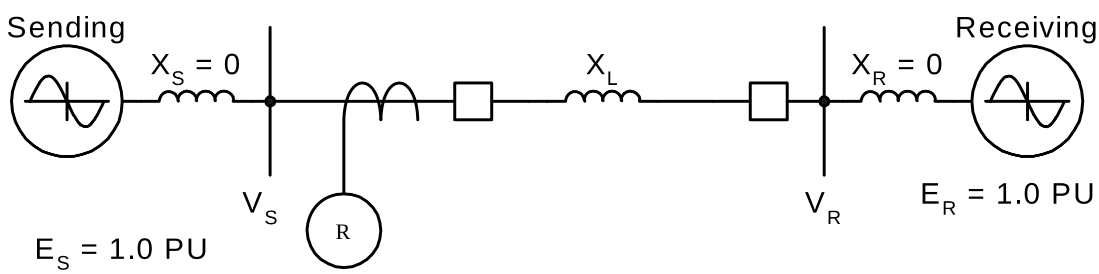



**Figure 1 – Maximum Power Transfer**

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$\delta$ = Voltage angle between $V_S$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$I_{real}$ = Real component of current

$V$ = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

$I_{total}$ is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$ (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

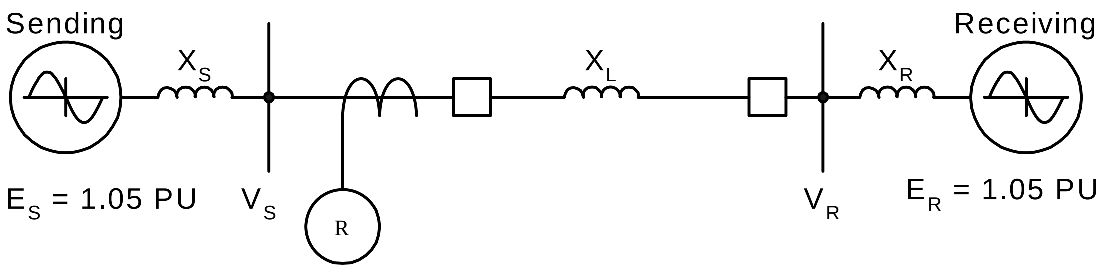



**Figure 2 – Site-Specific Maximum Power Transfer Limit**

The recommended procedure for determining $X_S$ and $X_R$ is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude ($I_{real}$) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

$V$ = Nominal phase-to-phase system voltage

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{\left(X_S + X_R + X_L\right)}}$$

Where:

$I_{total}$ = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

## R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess

of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

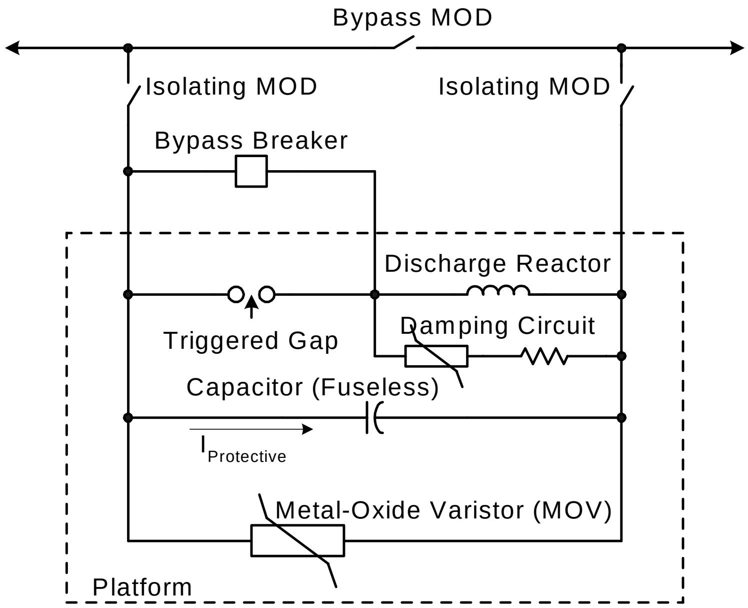



**Figure 3 – Series Capacitor Components**

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

$X_C$ = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because $I_{total}$, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. $I_{total}$ (where $I_{total}$ is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

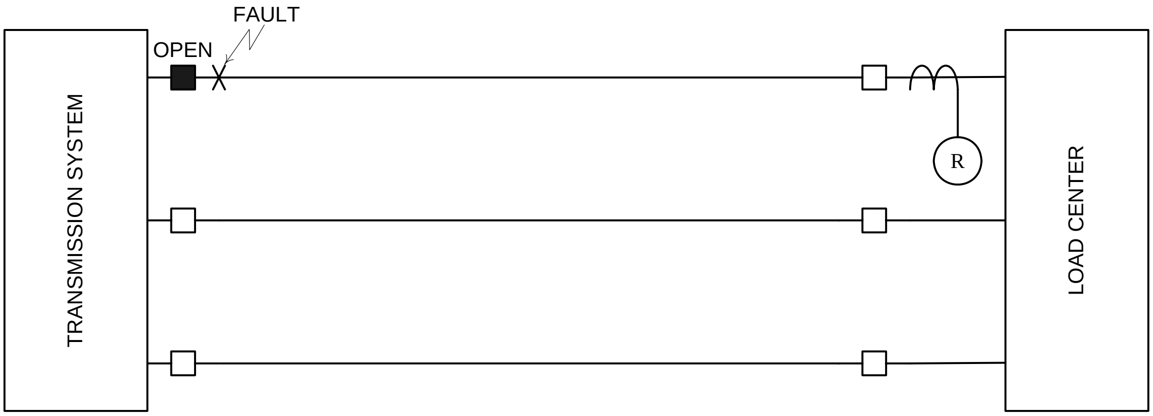



**Figure 4 – Weak Source Systems**

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{V_S{}^2 + V_R{}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$I_{max} = 1.15 \times \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{max} = 1.71 \times I_{fault}$$

Where:

$I_{fault}$ is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times $I_{fault}$, where $I_{fault}$ is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

## R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current ($I_{max}$) that the line will experience.

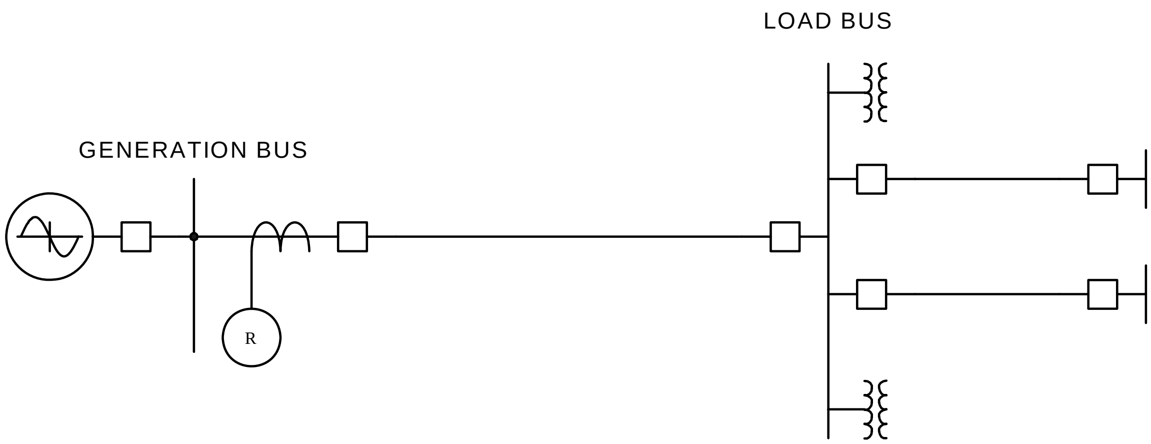



**Figure 5 – Generation Remote to Load Center**

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amperes at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}$$

Where:

$V_{relay}$ = Phase-to-phase voltage at the relay location

$N$ = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the $I_{max}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

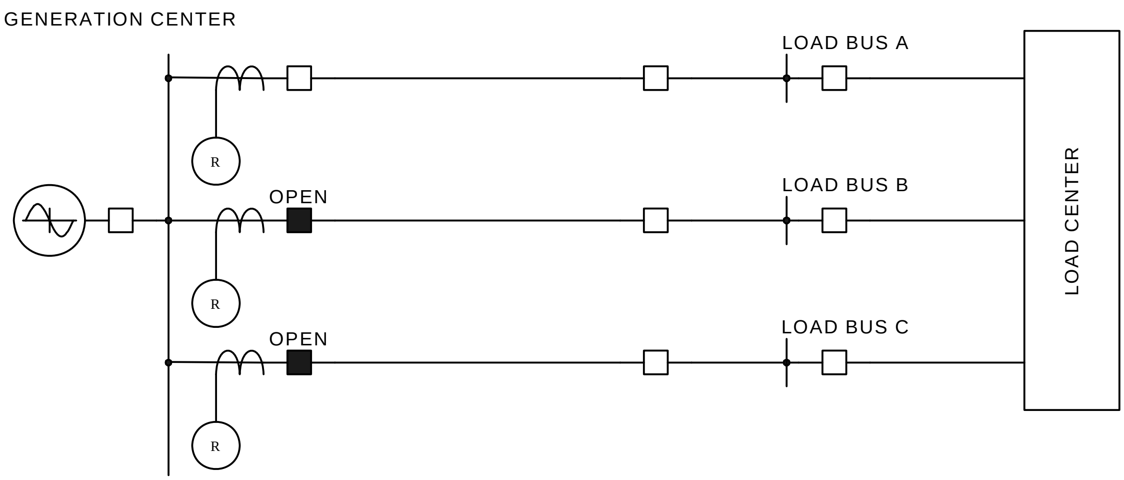



**Figure 6 – Generation Connected to System – Multiple Lines**

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The $I_{max}$ expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds $I_{max}$.

Set the tripping relay so it does not operate at or below 1.15 times $I_{max}$, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

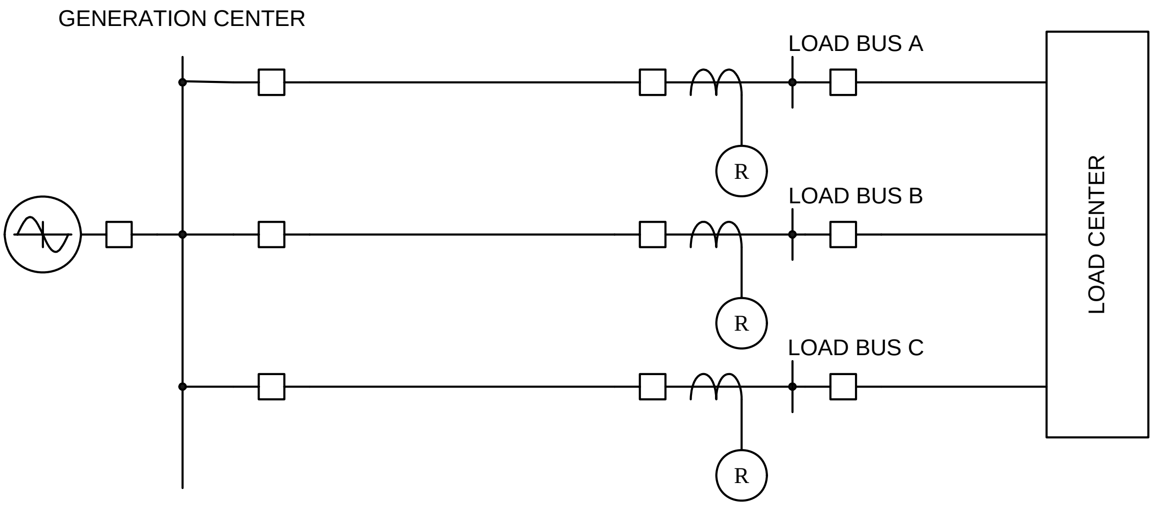



**Figure 7 – Load Remote to Generation**

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow ($I_{max}$) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

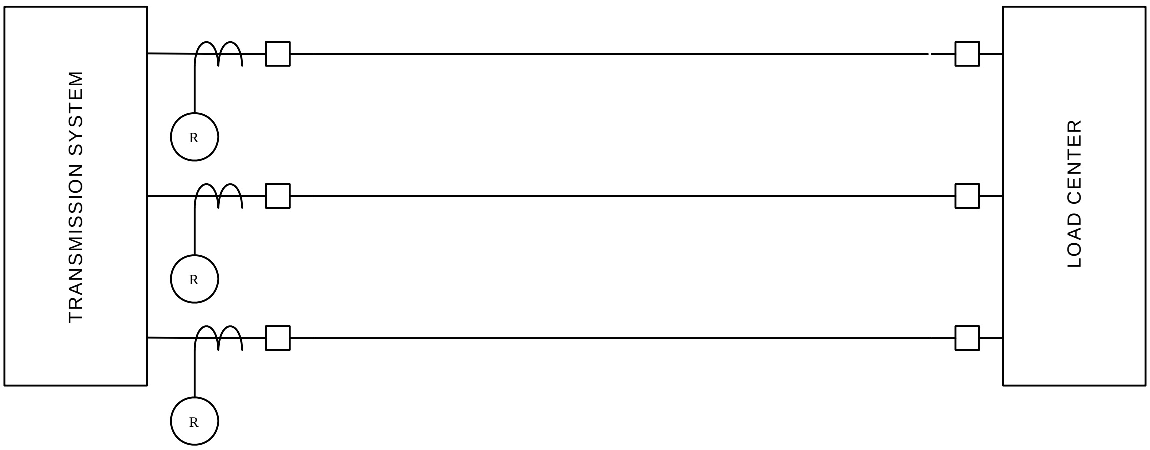



**Figure 8 – Remote Cohesive Load Center**

Also, one must determine the maximum power flow on an individual line to the area ($I_{max}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.

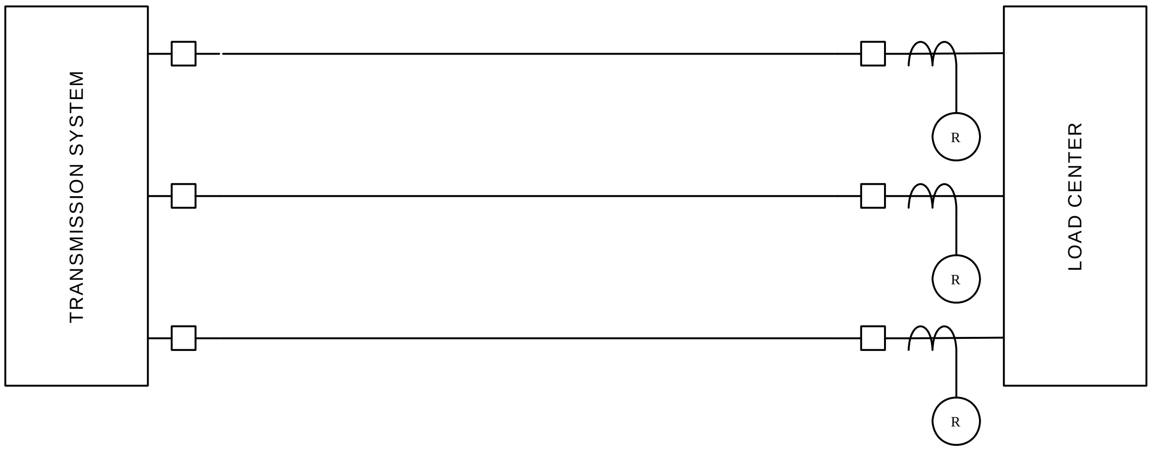



**Figure 9 – Cohesive Load Center Remote to Transmission System**

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow ($I_{max}$)from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

## R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer, and addresses protection that is intended to protect the transformer from thermal overloads.

1. Set the overload protection relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator-established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload, or
2. Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting shall be no less than 100° C for the top oil or 140° C[5] for the winding hot spot temperature.

## R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not “overly sensitive,” and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

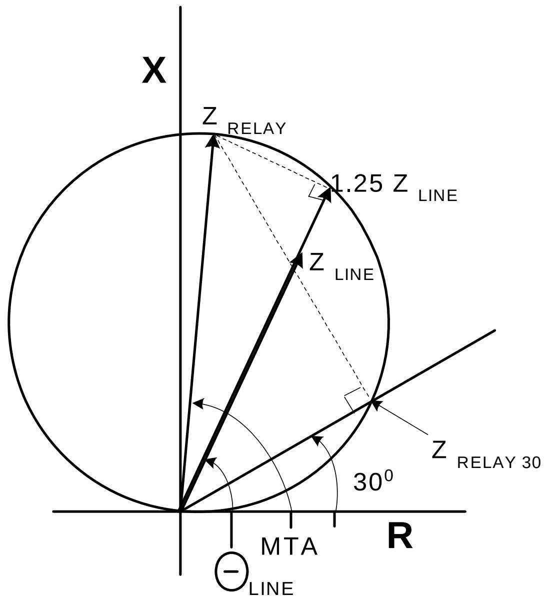



**Figure 10 – Long Line relay Loadability**

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

- $V_{relay}$ = Phase-to-phase line voltage at the relay location
- $Z_{line}$ = Line impedance
- $\Theta_{line}$ = Line impedance angle
- $Z_{relay}$ = Relay setting at the maximum torque angle
- $MTA$ = Maximum torque angle, the angle of maximum relay reach
- $Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current
- $I_{trip}$ = Trip current at 30 degrees with normal voltage
- $I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[ \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})} \right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(\ MTA - \Theta_{line}\ )}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(\ MTA - 30°\ )}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

## R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

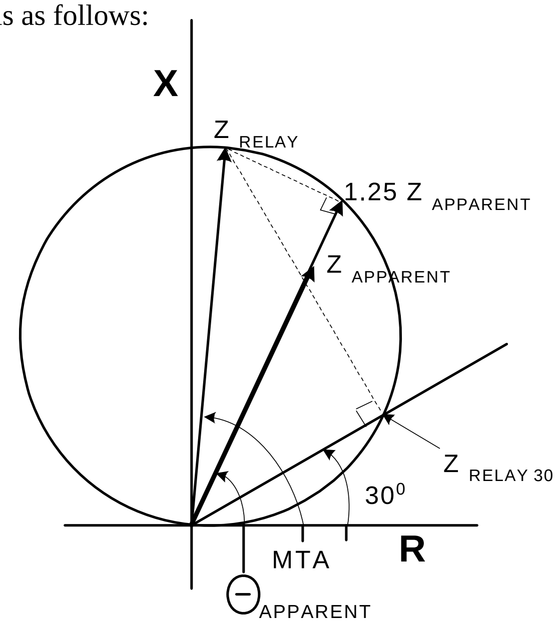



**Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps**

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

$Z_{relay}$ = Relay setting at the maximum torque angle.

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

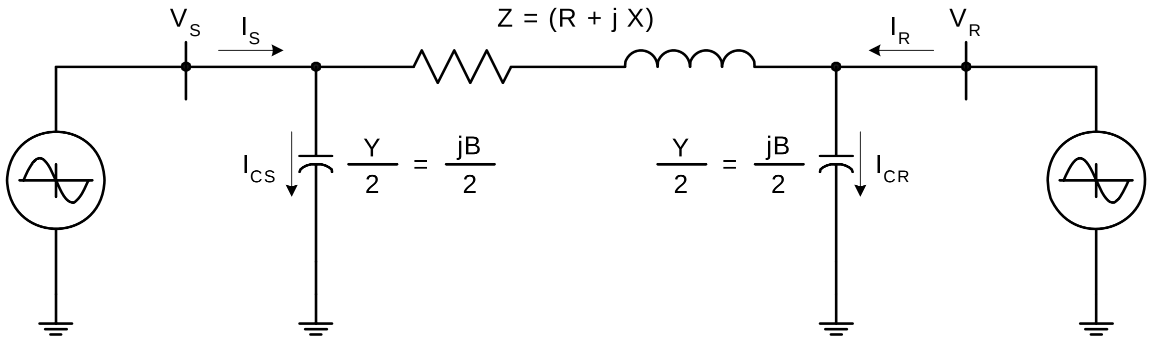
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

# Appendices

# Appendix A — Long Line Maximum Power Transfer Equations




Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{{V_S}^2}{|Z|}\cos(\theta^\circ) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta^\circ)$$

$$Q_{S3-\phi} = \frac{{V_S}^2}{|Z|}\sin(\theta^\circ) - {V_S}^2\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta^\circ)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos(\theta^\circ) + \sin(\theta^\circ)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta^\circ) - |Z|\frac{B}{2} - \cos(\theta^\circ)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{{I_{real}}^2 + {I_{reactive}}^2}}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$V$ = Nominal phase-to-phase bus voltage

$\delta$ = Voltage angle between $V_S$ and $V_R$

$Z$ = Reactance, including fixed shunt reactors, of the transmission line in ohms*

$\Theta$ = Line impedance angle

$B$ = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

# Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

## *Unmodified Permissive Overreaching Transfer Trip*

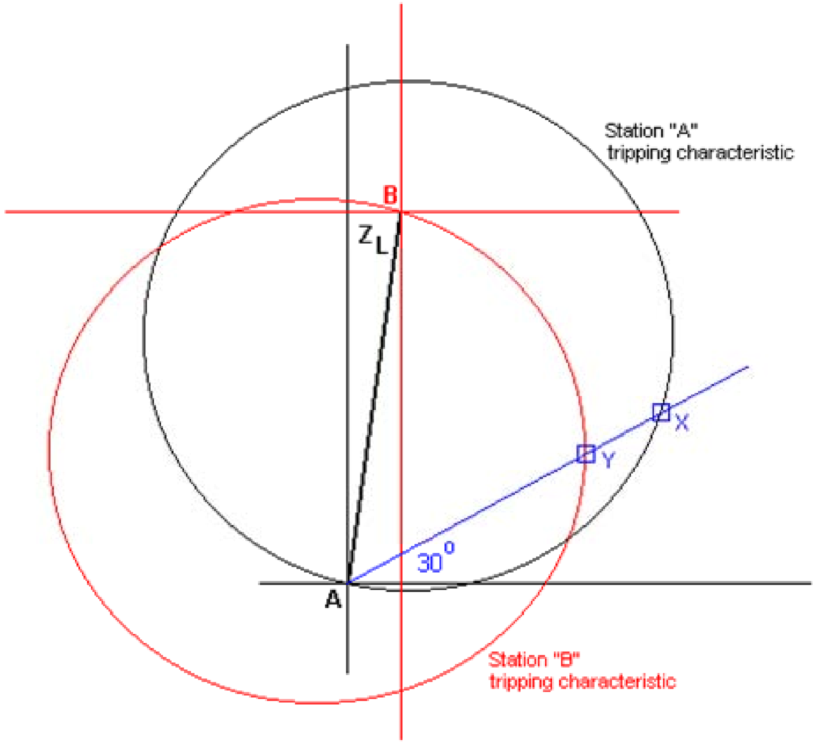



Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station "A" is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point "X" falls outside the tripping characteristic of the relay at Station "B", preventing tripping at either terminal. Relay "A" becomes susceptible to tripping along its 30-degree line only when point "Y" is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

## *Directional Comparison Blocking*

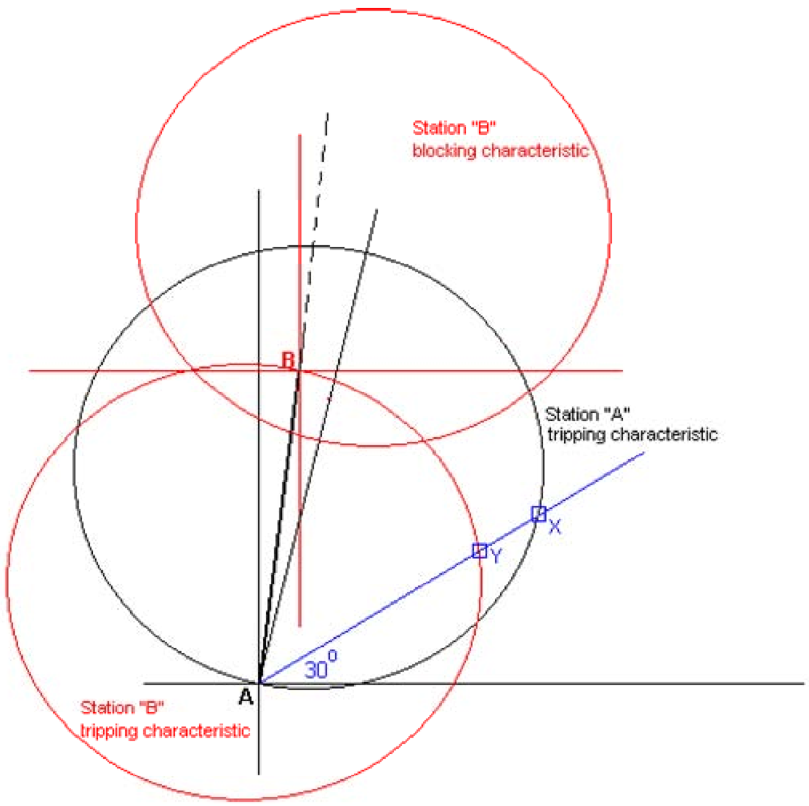



Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

# APPENDIX C — OUT-OF-STEP BLOCKING RELAYING

Out-of-step blocking is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability studies) or observed system swings.

There are many methods of providing the out-of-step blocking function; one common approach, used with distance tripping relays, uses a distance characteristic which is approximately concentric with the tripping characteristic. These characteristics may be circular mho characteristics, quadrilateral characteristics, or may be modified circular characteristics.

During normal system conditions the accelerating power, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa >> 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relative slowly at first; for a stable swing (where no generators “slip poles” or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure 1 below. .

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is approximately concentric to the related tripping relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to trip. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the tripping relay from operating.

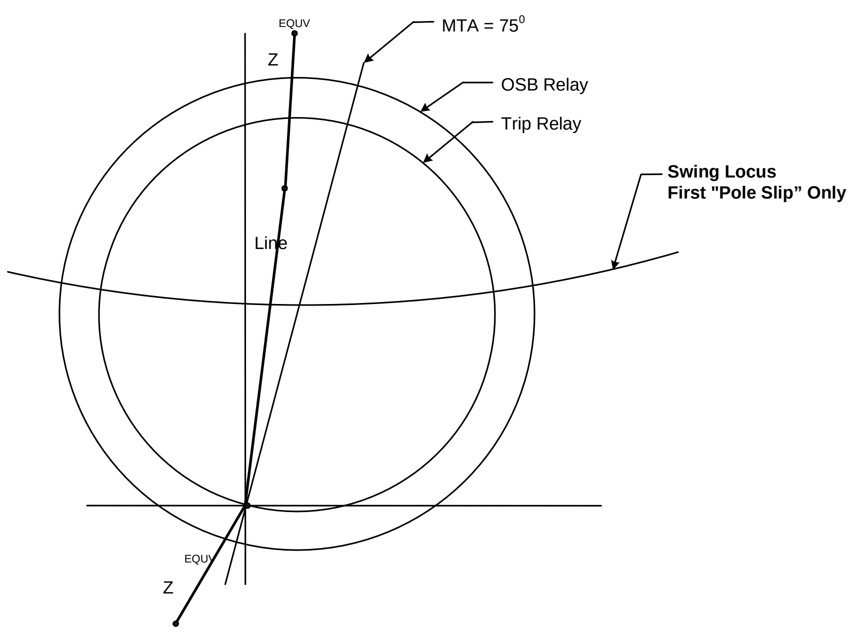



**Figure 1 –**

Figure 1 illustrates the relationship between the out-of-step blocking relay and the tripping relay, and shows a sample of a portion of an unstable swing.

## *Impact of System Loading of the Out-of-Step Relaying*

Figure 2 illustrates a tripping relay and out-of-step blocking relay, and shows the relative effects of several apparent impedances.

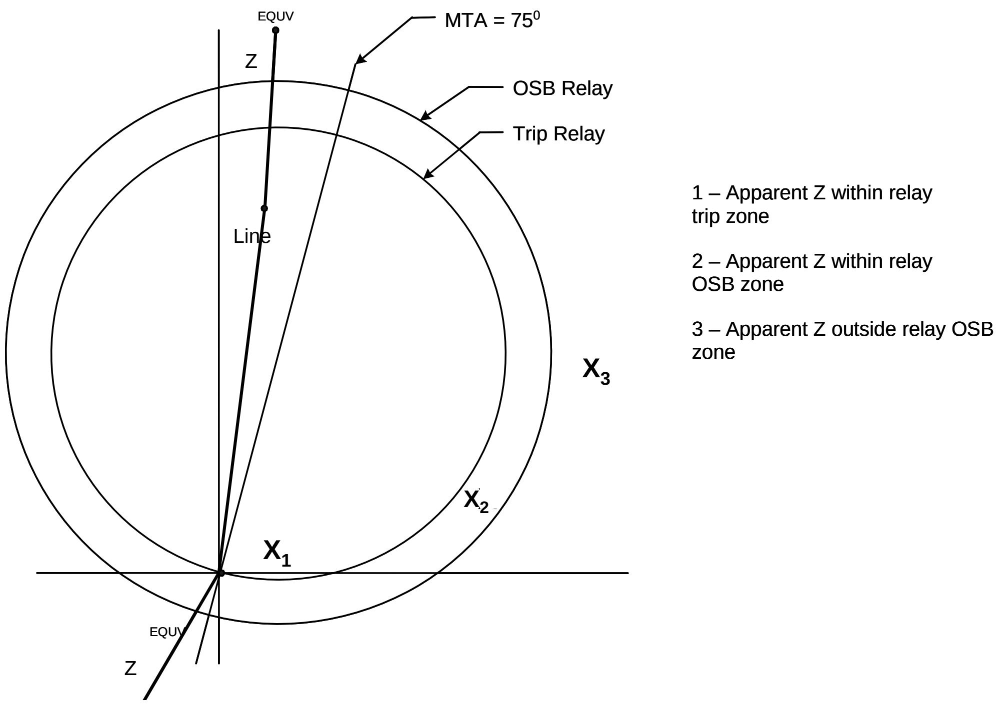



**Figure 2 – Out-of-Step Characteristics with Load**

Both the tripping relay and the out-of-step blocking relay have characteristics responsive to the impedance that is seen by the distance relay.  In general, only the tripping relays are considered when evaluating the effect of system loads on relay characteristics (usually referred to as “relay loadability”). However, when the behavior of out-of-step blocking relays is considered, it becomes clear that they must also be included in the evaluation of system loads, as their reach must necessarily be longer than that of the tripping relays, making them even more responsive to load.

Three different load impedances are shown.  Load impedance (1) shows an impedance (either load or fault) which would operate the tripping relay.  Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic, and illustrates the desired result.  The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the tripping relay.  It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition!  A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time.

# APPENDIX D — SWITCH-ON-TO-FAULT SCHEME

Introduction

Switch-on-to-fault (SOTF) schemes (also known as “close-into-fault schemes or line-pickup schemes) are protection functions intended to trip a transmission line breaker when closed on to a faulted line. Dedicated SOTF schemes are available in various designs, but since the fault-detecting elements tend to be more sensitive than conventional, impedance-based line protection functions, they are designed to be “armed” only for a brief period following breaker closure. Depending on the details of scheme design and element settings, there may be implications for line relay loadability. This paper addresses those implications in the context of scheme design.

## *SOTF scheme applications*

SOTF schemes are applied for one or more of three reasons:

1. When an impedance-based protection scheme uses line-side voltage transformers, SOTF logic is required to detect a close-in, three-phase fault to protect against a line breaker being closed into such a fault. Phase impedance relays whose steady-state tripping characteristics pass through the origin on an R-X diagram will generally not operate if there is zero voltage applied to the relay before closing into a zero-voltage fault. This condition typically occurs during when a breaker is closed into a set of three-phase grounds which operations/maintenance personnel failed to remove prior to re-energizing the line. When this occurs in the absence of SOTF protection, the breaker will not trip, nor will breaker failure protection be initiated, possibly resulting in time-delayed tripping at numerous remote terminals. Unit instability and dropping of massive blocks of load can also occur.

   Current fault detector pickup settings must be low enough to allow positive fault detection under what is considered to be the “worst case” (highest) impedance to the source bus.

2. When an impedance protection scheme uses line-side voltage transformers, SOTF current fault detectors may operate significantly faster than impedance units when a breaker is closed into a fault anywhere on the line. The dynamic characteristics of typical impedance units are such that their speed of operation is impaired if polarizing voltages are not available prior to the fault.

   Current fault detector pickup settings will generally be lower in this application than in (1) above. The greater the coverage desired, and the longer the line, the lower the setting.

3. Regardless of voltage transformer location, SOTF schemes may allow high-speed clearing of faults along the entire line without having to rely or wait on a communications-aided tripping scheme.

   Current or impedance-based fault detectors must be set to reach the remote line terminal to achieve that objective.

## *SOTF line loadability considerations*

This reference document is intended to provide guidance for the review of existing SOTF schemes to

ensure that those schemes do not operate for non-SOTF conditions or under heavily stressed system conditions. This document also provides recommended practices for application of new SOTF schemes.

1 The SOTF protection must not operate assuming that the line terminals are closed at the outset and carrying up to 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

2 For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding <u>75%</u> of nominal.

## SOTF scheme designs

*1 Direct-tripping high-set instantaneous phase overcurrent*

This scheme is technically not a SOTF scheme, in that it is in service at all times, but it can be effectively applied under appropriate circumstances for clearing zero-voltage faults. It uses a continuously-enabled, high-set instantaneous phase overcurrent unit or units set to detect the fault under "worst case" (highest source impedance) conditions. The main considerations in the use of such a scheme involve detecting the fault while not overreaching the remote line terminal under external fault conditions, and while not operating for stable load swings. Under NERC line loadability requirements, the overcurrent unit setting also must be greater than 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

*2 Dedicated SOTF schemes*

Dedicated SOTF schemes generally include logic designed to detect an open breaker and to arm instantaneous tripping by current or impedance elements only for a brief period following breaker closing. The differences in the schemes lie (a) in the method by which breaker closing is declared, (b) in whether there is a scheme requirement that the line be dead prior to breaker closing, and (c) in the choice of tripping elements. In the case of modern relays, every manufacturer has its own design, in some cases with user choices for scheme logic as well as element settings.

In some SOTF schemes the use of breaker auxiliary contacts and/or breaker "close" signaling is included, which limits scheme exposure to actual breaker closing situations. With others, the breaker-closing declaration is based solely on the status of voltage and current elements. This is regarded as marginally less secure from misoperation when the line terminals are (and have been) closed, but can reduce scheme complexity when the line terminates in multiple breakers, any of which can be closed to energize the line.

## SOTF and Automatic Reclosing

With appropriate consideration of dead-line reclosing voltage supervision, there are no coordination issues between SOTF and automatic reclosing into a de-energized line. If pre-closing line voltage is the primary means for preventing SOTF tripping under heavy loading conditions, it is clearly desirable from a

security standpoint that the SOTF line voltage detectors be set to pick up at a voltage level below the automatic reclosing live-line voltage detectors and below 0.8 per-unit voltage.

Where this is not possible, the SOTF fault detecting elements are susceptible to operation for closing into an energized line, and should be set no higher than required to detect a close-in, three-phase fault under worst case (highest source impedance) conditions assuming that they cannot be set above 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023). Immunity to false tripping on high-speed reclosure may be enhanced by using scheme logic which delays the action of the fault detectors long enough for the line voltage detectors to pick up and instantaneously block SOTF tripping.

# Appendix E — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, *IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13, *American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)*, 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
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| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

The Relay Loadability standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The standard and implementation plan were modified in response to the comments.

In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
  - ***Same-day Operations****:* routine actions required within the time frame of a day, but not real-time.
  - ***Real-time Operations****:* actions required within one hour or less to preserve the reliability of the Bulk Electric System.
  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted "levels of non-compliance" and added "violation severity levels" to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☐ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☐ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments:

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Group Comments (Complete this page if comments are from a group.)

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**Lead Contact:** Richard J. Kafka

**Contact Organization:** Pepco Holdings, Inc

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|---|---|---|---|
| Carl Kinsley | Delmarva Power & Light | RFC | 1 |
| Alvin Depew | Potomac Electric Power Company | RFC | 1 |
| Evan Sage | Potomac Electric Power Company | RFC | 1 |
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In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
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  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted "levels of non-compliance" and added "violation severity levels" to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement.  Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section “F” to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☒ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: PRC-023-1 Section F lists a reference document -PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings-. There is no statement in the actual standard as to whether the information and requirements contained within the reference document are part of the standard. The introductory sentence in the Reference Document states -This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.- It says it provides information and guidance, not requirements. Yet there are specific requirements contained within the reference document (such as Switch-on-to-Fault Setting Requirements). Either all requirements should be listed in the actual standard itself, or the standard should indicate there are additional requirements contained within the Reference Document. In addition, Appendix D of the Reference Document states the following: -For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal.- The report is dated January 9, 2007, but the PRC-023-1 standard is not yet approved. The stated requirement mentioned above should not reference the date of formal adoption of the report, but the date of the formal adoption of the standard.

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
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| Organization: Sufana Engineering, Inc. | | |
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| E-mail: C.R.Sufana@ieee.org | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☒ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   ☐ Yes

   ☐ No

   Comments:

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   ☒ Field testing is necessary

   Comments: I would think that at least some of the lines should be tested to see if any of the NERC proposed requirements are actually able to be used.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: This standard totally lacks fully worked out examples as to how to set the zone 3 relays. I would like to see complete detailed examples for each of the Relay Phase Settings sections. As the standard is presented now, it is essentially useless to the actual relay setter. Each example should have a complete ratings list of all of the equipment on the line (both summer and winter, short time, emergency, etc), the actual procedure of doing the relay setting (including comparing the apparent impedance versus the results based on loading), and final values for the sample lines. For each R1.xx, the first example should include a two terminal line. The second example for each R1.xx should include a three terminal line that has a very weak source. Each example should also show different relay shapes, i.e. mho, lens, trapezoidal, mho with a notched out section, trapezoidal with a notched out section, etc. There should also be fully worked out examples for current only based relays.

If the relay has the ability to notch out part of the characteristic around the line load angle, then questions as to how close to the angle should be addressed, i.e. if 30 degrees is the load angle, is plus/minus 5 degrees (thus the area from 25 to 35 degrees is notched out) OK? How close to the loadability point should the relay setting be should also be addressed. For all examples, a case that is deemed acceptable and one that is considered in violation should be presented.

I have had to set several 3 terminal lines that had a weak source that was actually an autotransformer tied to the line via a breaker. The resultant apparent impedance was so high that any setting would have been violation of the normal approach of using 1.15 times Irating. The result was that sequential tripping (which I consider to be not a good way to do things) was going to happen if the communications failed and that dual and perhaps triple layers of communication were needed. A fully worked out example of this type case should be included.

So the bottom line is that for each example, I would like to see the entire equipment rating list, the fault study results, and how the actual setting was determined. If it takes 20 pages to show the example, so be it. Examples that are only a two terminal lines will be considered by me to be insufficient.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Ed Davis | | |
| Organization: Entergy Services, Inc | | |
| Telephone: 504-576-3029 | | |
| E-mail: edavis@entergy.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ Yes

   ☒ No

   Comments:

   We think the RC should not be the exclusive determinator of - critical to the reliability of the BES -, especially since the other entities are required to expend resources to comply with that determination. Therefore, we suggest the responsible entites under R3 be changed from - RELIABILITY COORDINATOR SHALL DETERMINE - to - RELIABILITY COORDINATOR, IN CONJUNCTION WITH TRANSMISSION OWNERS, GENERATION OWNERS, AND DISTRIBUTION PROVIDERS SHALL DETERMINE. This change should be made in R3, along with our suggested change to the Appicability comment in response to Question 6 below.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

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   ☐ I agree with the Violation Severity Levels.

☒ I do not agree with the following Violation Severity Levels.

Comments:

The VRF for R1 is HIGH which we suggest should be MEDIUM. The specification of a particular criteria will not cause cascading outages. The use of a VRF of HIGH for relays should be applied to relays not set to the criteria.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

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   ☒ No field testing is necessary

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Comments:

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☐ No additional comments

Comments:

The industry has determined that NERC reliability standards need to be more definitive as to which entities the standards are Applicable. Therefore, Entergy strongly suggests that all Applicability assignments in ALL standards and requirements be changed to be very specific. Recognizing the greater Applicability specified in this draft of the standard we think greater specificity is required. Therefore, we suggest the Applicability of each standard be changed to - ALL REGISTERED xxx, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD, where xxx is the functional entity to whom the standard applies. Therefore, the Applicability of PRC-023-1 should not be Transmission Owners but should be changed to - ALL REGISTERED TRANSMISSION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Reliability Coordinators should be changed to - ALL REGISTERED RELAIBILITY COORDINATORS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD;Generation Owners but should be changed to - ALL REGISTERED GENERATION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Distribution Providers but should be changed to - ALL REGISTERED DISTRIBUTION PROVIDERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD.

The Applicability sections 4.1.2 and 4.1.4 should be changed from - AS DESIGNATED BY THE RELIABILITY COORDINATOR AS CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM - to - AS DESIGNATED BY THE RESULTS OF R3 OF THIS STANDARD.

In Applicability sections 4.2 and 4.3, please clarify the meaning, or applicability, of the term - applied according to 4.1.1 through 4.1.4. It is not clear what is meant by that phrase.

R3 contains the nebulous term - ARE CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM. This phrase is too vague and should be replaced by - ARE LIMITING FACILITIES DEFINED BY IROLs.

Measure M1 contains R1 and R4 in parentheses. We do not understand the meaning. Please re-write M1 so the relevance of R1 and R4 is clear.

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Southern Company Transmission

**Lead Contact:** Roman Carter

**Contact Organization:** Southern Co. Transmission

**Contact Segment:** 1

**Contact Telephone:** 205-257-6027

**Contact E-mail:** jrcarter@southernco.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Marc Butts | Southern Co Trans | SERC | 1 |
| JT Wood | Southern Co. Trans | SERC | 1 |
| Phil Winston | Georgia Power Co. | SERC | 1 |
| Ben Pilleteri | Alabama Power Co. | SERC | 1 |
| Steve Carter | Gulf Power Co. | SERC | 1 |
| Joseph Stewart | Mississippi Power Co. | SERC | 1 |
| Jim Busbin | Southern Co. Trans | SERC | 1 |
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### Background Information

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In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
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  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
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- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: Mitigation Time Horizons should not be used as a means for determining non-compliance monetary penalties. The Violation Risk Factors already incorporate whether a requirement is real-time or in the future. Therefore, Southern Company recommends that the monetary penalties be based only on the violation risk factors and violation severity levels and NOT on the Mitigation Time Horizons.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☒ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☒ No additional comments

   Comments:

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Anita Lee | | |
| Organization: Alberta Electric System Operator - AESO | | |
| Telephone: 403 539 2497 | | |
| E-mail: anita.lee@aeso.ca | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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**Background Information**

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  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
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- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: The WECC currently maintains the bulk transfer path catalog which provides a list of the critical facilities. It may be more appropriate for the RRO to be the entity responsible for making the determination on critical facilities.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: 1. Section D 2.2.1 "Evidence that the relay settings comply with criteria in R1.1 through 1.13 exists but is incomplete or incorrect for one or more of the requirements" - we recommend adding the word "applicable" before the word "criteria" since the present wording could imply that compliance is required for all of the criteria.

   2.Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13". Firstly, "thought" should be changed to "through"; secondly, we think that it would be more appropriate to have different violation severity levels corresponding with the number of non-compliance to the sub-requirements (R1.1 to R1.13), instead of assigning the highest severity level for non-compliance with any one of the sub-requirements.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☐ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

Comments:

1. Thermal Relays - Some direction should be provided regarding the use of themal emulation relays, either in the standard exclusions or in the reference document.

2. We have a concern about loading to 115% of the 15 minute rating for overhead lines. Specifically because ratings are often based on maximum allowable sag according to the National Electric Safety Code and intentionally loading above that level represents a safety code violation.

3. Determining and granting allowance for technical exceptions was previously done by the RRO. If this responsibility is assigned to the Reliability Coordinator there may not be consistency across the region.

4. R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. Four hour ratings are not presently used within Alberta.

5.R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 p.u. voltages. For the bus voltage to dip to 0.85 p.u. the system impedance will have thavd to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in teh WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** WECC Relay Work Group

**Lead Contact:** Paul Rice

**Contact Organization:** WECC

**Contact Segment:** Transmission Owners

**Contact Telephone:** 801-582-0353

**Contact E-mail:** paul@wecc.biz

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Dean Bender | Bonneville Power Administration | WECC | 1 |
| Dick Curtner | Public Service of New Mexico | WECC | 1 |
| Malkiat Dhillon | Sacramento Municipal Utility District | WECC | 1 |
| Gene Henneberg | Sierra Pacific Power Co. | WECC | 1 |
| Mike Ibold | Xcel Energy | WECC | 1 |
| Bill Middaugh | Tri-State Gen. and Trans. Ass'n. | WECC | 1 |
| Dan Shield | Alberta Electric System Operator | WECC | 1 |
| Randy Spacek | Avista Corp. | WECC | 1 |
| Jonathan Sykes | Salt River Project | WECC | 1 |
| Ed Taylor | Pacific Gas & Electric | WECC | 1 |
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- **Associated Documents**
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You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: While we agree that the horizons are probably adequate we have two areas of concern. The first is the discrepancy between the 39 months in A.5.1.2 and the 24 months in B.R4. Secondly we suggest that horizons be implemented to accommodate correction of issues of Security Level violations that may be found in the future.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: We suggest the wordings for the specific sections in D.2. be changed to those shown below:

   D.2.1.1 The applicable criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

D.2.2.1 Evidence that relay settings comply with the applicable criteria in R1.1 through R1.13 exists, but is incomplete or incorrect for one or more of the requirements.

D. 2.4.1 Relay settings do not comply with any requirement R1.1 through R1.13 or evidence does not exist to support that relay settings comply with any one of the criteria in R1.1 through R1.13.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

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   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments: While we don't necessarily believe that additional field testing is necessary for the proposed standards, standard 1.3.2 is different from the original exception 4 and will not have been tested. This also changes the requirements for series-compensated lines.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: Some thermal emulation relays are used in SPS, but since they could operate independent of the SPS we wonder if there ought to be some discussion of them in the standard exclusions, or in the reference.

   We suggest that, for clarity, "Facility" and "Facility Rating" definitions be copied from the "Glossary of Terms Used in Reliability Standards" to be included in either the standard or the reference.

   We have concerns about loading to 115% of the 15 minute rating for overhead lines. Those ratings are often based on maximum allowable sag according to the National Electric Safety Code. Intentionally loading above that level may be in violation of the safety code.

   Previously the RRO had responsibility in determining allowance of technical exceptions, which provided consistency throughout the entire region. Moving those responsibilities to the Reliability Coordinators (RC) may change that consistency, thus treating entities differently depending on their RC.

   R1 - There is no longer a loadability rating based on breaker rating (Exception 3).

   R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. We have found that entities typically have continuous and short term, i. e., 15 minute, ratings defined, but not 4 hour ratings.

   R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 per unit voltages. For the bus voltage to dip to 0.85 per unit the system impedance will have had to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in the WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008.

   R1.4 - The current calculation for Exception 5 could have been based on Exception 2, 3, or 4 but was frequently based on 4. Since 4 has been significantly changed it will also change the allowed loadability of R1.4. We believe that this is another reason to keep R1.3.2 to be determined in the same manner as Exception 4.

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| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Brian Thumm | | |
| Organization: ITC Transmission | | |
| Telephone: 248-374-7846 | | |
| E-mail: bthumm@itctransco.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
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- **Associated Documents**
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You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: There is insufficient material describing the development and use of mitigation time horizons for inclusion in the Reliability Standards. It is premature to include them in these version of the Standards. When the Reliability Standards Development Procedure is updated to include a detailed description of their meaning and usage, only then should they be included in a Reliability Standard.

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   ☒ I agree with the Violation Severity Levels.

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   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

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   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: Requirements R1.1 and R1.2 are written to allow transmission relays to be set as a percentage of "seasonal Facility Ratings" for a "defined loading duration." Not all transmission owners assign seasonal ratings to their transmission facilities (i.e., there is one rating for the full year). Also, not all transmission owners have time-of-use ratings (e.g., 4-hour emergency ratings, 15-minute emergency ratings). Perhaps there is a way to clarify the requirements to ensure an entity with one rating is not in jeopardy of being found non-compliant sinply for not having a seasonal rating. ITC Transmission recommends a footnote to that effect, indicating that if seasonal ratings do not apply for a particular facility, then the full-year rating is to be used. Similarly, a footnote could also clarify that if a short-term or emergency rating has not been established for a particular facility, then the normal rating would apply (which, notably, would be more conservative than an emergency rating, since emergency ratings are generally higher than normal ratings).

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | Herb Schrayshuen | |
| Organization: | National Grid | |
| Telephone: | (315) 428-3159 | |
| E-mail: | herbert.schrayshuen@us.ngrid.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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   Comments: Section D, 2.4.1 states a Severe level violation applies when "Relay settings do not comply with R1.1 through R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13." National Grid agrees that non-compliance of relay settings should constitute a Severe level violation. However, we believe that in cases where "Relay settings comply with one of the criteria in R1.1 through R1.13, but evidence does not exist to support that the relay settings comply" that a High level violation should apply.

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   Comments: The schedule for Switch-On-To-Fault (SOTF) protections applied on elements 200 kV and above is the same as the Beyond Zone 3 schedule for the phase protections referenced in section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the Standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2.

In Section B, Requirement R1.10 additional specificity should be provided regarding the word applicable in the phrase "applicable maximum transformer nameplate rating.

In Section B, Requirement R1.11 additional specificity should be provided to clarify that the word supervision refers to blocking tripping of the transformer overload protection relays when the top oil or winding hot spot temperature is below the value specified in the Standard.

Investigation of protective relay misoperations sometimes identifies firmware problems that cause a relay to operate in an manner not intended by the manufacturuer. How would compliance be assessed in a case where a firmware problem is identified that prevents a relay from meeting the the relay loadability requirements? What process would exist for granting exemption from the Standard for such a problem that would affect all Entities that have applied the protective relay in question?

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| Name: | | |
| Organization: | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:** Ed Taylor

**Contact Organization:** Pacific Gas and Electric Co.

**Contact Segment:** 1

**Contact Telephone:** (510) 874-2211

**Contact E-mail:** eat3@pge.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Chifong Thomas | Pacific Gas and Electric Co | WECC | 1 |
| Glenn Rounds | Pacific Gas and Electric Co | WECC | 1 |
| Tom Siegel | Pacific Gas and Electric Co | WECC | 1 |
| Vahid Madani | Pacific Gas and Electric Co | WECC | 1 |
| Ben Morris | Pacific Gas and Electric Co | WECC | 1 |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

### Background Information

The Relay Loadability standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The standard and implementation plan were modified in response to the comments.

In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
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  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted "levels of non-compliance" and added "violation severity levels" to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments: The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments: While we agree that the horizons are probably adequate we have two areas of concern. The first is the discrepancy between the 39 months in A.5.1.2 and the 24 months in B.R4. Secondly we suggest that horizons be implemented to accommodate correction of issues of Security Level violations that may be found in the future.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: We suggest the wordings for the specific sections in D.2. be changed to those shown below:

   D.2.1.1 The applicable criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

D.2.2.1 Evidence that relay settings comply with the applicable criteria in R1.1 through R1.13 exists, but is incomplete or incorrect for one or more of the requirements.

D. 2.4.1 Relay settings do not comply with any requirement R1.1 through R1.13 or evidence does not exist to support that relay settings comply with any one of the criteria in R1.1 through R1.13.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

☐ No field testing is necessary

☒ Field testing is necessary

Comments: Yes. field testing is recommended. Successful implementation depends on close communication between the Planning Authority, Transmission Operator and Reliability Coordinator. Requirements for documentation of compliance need to be clearly defined and understood by all parties.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments:

(1)There are some technical differences between PRC-023 and NERC Recommendation 8a that need to be resolved. For example, NERC Recommendation 8a defined a term called the "Emergency Ampere Rating" of a transmission line, which includes an explanation of how this rating should be determined. NERC PRC-023 requires the use of a "Facility Rating" to determine the circuit loadability. The term "Facility Rating" should be similarly defined so as not to cause confusion later, especially if no field test is applied before implementation. Other specific comments on the technical differences between PRC-023 and NERC Recommendation 8a will be sent in by the WECC Relay Work Group.

(2) Need more clarification on SPS Schemes. Are all SPS schemes exempt or only the ones that meet NERC Reliability Criteria? Some SPS schemes are local in nature, do not affect neighboring utilities and failure of one of these schemes would not result in cascading events. These local SPS schemes may not be designed with the same degree of redundancy as SPS schemes that are in the WECC catalog and have been reviewed by the WECC RAS Reliability Subcommittee.

(3) Are line thermal overload schemes exempt? They are designed to take corrective action to prevent overloading a transmission line and by their nature may prevent loading the transmission line to levels required by R1.1 through R1.13.

(4) If a relay setting is found to not comply, is there an implementation period to comply?

(5) No sanctions have been associated with the different levels of non-compliance. When will these be defined?

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** FRCC

**Lead Contact:** Eric Senkowicz

**Contact Organization:** FRCC

**Contact Segment:** 2

**Contact Telephone:** 813-289-5644

**Contact E-mail:** esenkowicz@frcc.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mark Bennett | Gainesville Regional Utilities | FRCC | 5 |
| Linda Campbell | FRCC | FRCC | 2 |
| Alan Gale | City of Tallahassee | FRCC | 5 |
| Eric Grant | Progress Energy - Florida | FRCC | 1 |
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## Background Information

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In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:
  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning**:* operating and resource plans from day-ahead up to and including seasonal.
  - ***Same-day Operations**:* routine actions required within the time frame of a day, but not real-time.
  - ***Real-time Operations**:* actions required within one hour or less to preserve the reliability of the Bulk Electric System.
  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted "levels of non-compliance" and added "violation severity levels" to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:
  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
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- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: The shift from RRO to RC accountability for determination of "circuits critical to the reliability of the Bulk Electric System" is a significant step change in current NERC Reliability philosophy. One concern we have is for consistency across the Regions and the change in this standard would shift that concern to consistency across RCs of the Interconnections.

   The second concern is that this will effectively shift some of the RC functions and accountabilities over to a role as a Compliance monitor. Some of the compliance elements associated with the new RC relationships may create inadvertent coordination and compliance measuring conflicts between the new Regional Entities, the RCs and the transmission owners that will ultimately have to comply with PRC-023.

   Based on the above we recommend removal of the RC related requirements and applicabilities until NERC (as the ERO) can better define the criteria or methodology for determining "circuits critical to the reliability of the Bulk Electric System" or establish a standardized Rliebility Impact Based methodology for RCs to use when creating the critical circuits list (circuits between 100 kV and 200 kV).

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: The "Mitigation Time Horizons" are not part of the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006. As such it is not clear why these were included in this standard.

   We understand the description of "Mitigation Time Horizons" is provided in the comment form and the concept of "Violation Time Horizons" is included in the Sanctions Guidelines, appendix 4B (NERC Compliance Filing to FERC dated October 18th, 2006), but we feel these horizons are part of a broader policy issue and since their use is not clearly stipulated in the NERC standards process, including them in the standards will cause unnecessary confusion to stakeholders and regulators.

The mitigation (or violation) time horizons should be clearly stipulated in the Reliability Standards Development Procedure prior to their use in any standard (from a policy perspective).

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: Although the violation severity levels (Lower, Moderate, High and Severe) are defined in the comment form provided and described as the basis for the DT's determinations, the levels are NOT defined in the current Reliability Standards Development Procedure. The term 'violation severity levels' is referenced generally in the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006 in the 'Compliance Elements of a Standard' section, as follows:

   (Violation Severity Levels) - 'Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are balloted with the standard, and developed by the NERC compliance program in coordination with the standard drafting team.'

   Since the standards procedure does NOT include the definitions for Lower, Moderate, High and Severe, our main concern, again, is from a policy perspective. Although the definitions are included in the comment form, we feel this track will lead to confusion among stakeholders and regulators in this and other standard development activities. The process is requesting the industry to ballot and comment on a concept (Lower, Moderate, High and Severe) that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions.

   The levels should be defined in the Reliability Standards Development Procedure prior to inclusion in balloting any standards.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☐ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☐ No field testing is necessary

   ☒ Field testing is necessary

   Comments: This standard is extremely technical in nature as evidenced by the development of PRC-023 Reference document. The new concepts being addressed in the standard will also result in the involvement of new industry participants that have not been historically, involved in the NERC Reliability Standards process and the accompanying compliance concepts.

   Based on the above, we recommend that a field test of the standard, to validate the measures and compliance elements, may highlight discrepancies and deficiencies in the measurability of the standard. We also feel that the field test may add additional insight and detail which could be added to the reference document or training material associated with the adoption of the standard.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: We have a concern with the associated "reference document", PRC-023 Reference. It is not clear how and where this document was developed. We understand that the document was created from previous references developed by the SPCTF. We would like to see a more formal vetting process of "reference documents".

The cover sheet indicates it was prepared by the SPCTF of the NERC Planning Committee and that it is version 1.0, dated January 9, 2007. In review of meeting histories, we were not able to find the "formal" approval or adoption process of this document by the SPCTF or the PC.

We recommend that reference documents of this type should include a revision history along with approval history indicating what quality checks were performed on the document and which body (SPCTF, PC) sponsored its development and approved its publication.

If a reference document is created outside of the standards process it should contain an appropriate disclaimer stating so, to ensure that it is clear that Reliability standard in effect during compliance activities take precedence over references. This would be important, especially if synchronization or interpretation conflicts existed between the reference document and the Reliability standard.

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: | D. Bryan Guy | |
| Organization: | Progress Energy Carolina, Inc. | |
| Telephone: | 919-546-4107 | |
| E-mail: | bryan.guy@pgnmail.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

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- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: Not as written. Requirement 3.1 requires that the RC have a process to determine critical 100-200kV lines that must meet relay loadability requirements. Req 3.1.1 requires that the RC coordinate with adjoining RCs.

   The standard should also include a provision, Req 3.1.2, that requires the RC process to also coordinate with the facility Transmission Owner(s) in addition to the adjoining RCs.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☒ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

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   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☒ No additional comments

   Comments:

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** NPCC CP9 Reliability Standards Working Group

**Lead Contact:** Guy V. Zito

**Contact Organization:** NPCC

**Contact Segment:** 10

**Contact Telephone:** 212-840-1070

**Contact E-mail:** gzito@npcc.org

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Ralph Rufrano | New York Power Authority | NPCC | 1 |
| David Kiguel | Ontario Hydro | NPCC | 1 |
| Roger Champagne | Hydro Quebec TransEnergie | NPCC | 1 |
| Ed Thompson | Con Edison | NPCC | 1 |
| Bill Shemley | ISO-New England | NPCC | 2 |
| Kathleen Goodman | ISO- New England | NPCC | 2 |
| Greg Campoli | New York ISO | NPCC | 2 |
| Ron Falsetti | The IESO, Ontario | NPCC | 2 |
| Jerad Barnhart | NSTAR | NPCC | 1 |
| Donald Nelson | MA. Dept of Tele. and Energy | NPCC | 9 |
| Guy V. Zito | NPCC | NPCC | 10 |
| Brian Hogue | NPCC | NPCC | 10 |
| Bill Shemley | ISO-New England | NPCC | 2 |
| Murale Gopinathan | Northeast Utilities | NPCC | 1 |
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- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning**:* operating and resource plans from day-ahead up to and including seasonal.
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- **Associated Documents**
  The drafting team added a section “F” to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☒ No

   Comments: NPCC participating members believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level and an approved Regional performance based methodology should be used to consistently determine this on a wide area basis. However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize the Drafting Team's critera.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

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   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: (1) Section D 2.4.1 should be changed to read as follows, to correspond with B R.1 and to correct an error: "Relay settings do not comply with at least one of R 1.1 though R 1.13, or evidence does not exist to support that relay settings comply with at least one of R 1.1 through R 1.13.

(2) Section D, 3.3.1 (Reliability Coordinator does not provide the list….) should be moved to the Severe level, 3.4.2 (Reliability Coordinator does not maintain a current list of facilities….) should be moved to the High level.

From our perspective there are 3 key elements in establishing the list of facilities critical to the reliability of the bulk electric system: 1) determining the facility list, 2) communicating the list to asset owners, and 3) maintaining the list.

The intent of R3 is to ensure that facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating the list of critical facilities is, in our view, one of the most important requirements, and there is no partial communicating so it's a case of either full compliant or flat out non-compliant. We therefore propose that 3.3.1 be moved to the Severe level.

If we accept the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does imply that the list has been communicated to the facility owners, and the requirement to maintain the list can be partially met. On the other hand, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 (Reliability Coordinator does not maintain a current list of facilities..) be moved to the High level.

Determining which facilities are critical to the reliability of the electric system is also an important first step. We agree that 3.4.1 should be retained at the Severe level, but propose to revise the sentence to read: "Reliability Coordinator does not have a process in place to determine, or evidence that it has determined, facilities that are critical to the reliability of the electric system."

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

☐ No field testing is necessary

☒ Field testing is necessary

Comments: NPCC participating members believe the need for further field testing depends on the outcome of the final determination of what constitutes the BPS. Additional time or effort for field testing may be required to not only come into compliance if large additional portions of the lower voltage electric system are included, but to test the validity and coordination of the concepts contained in this standard. During NERC SPCTF's previous efforts pertaining to Beyond Zone 3 the application of the concepts were somewhat confined.

NPCC participating members believe the Standard as written should not be restricted to voltage classifications and should be applied to performance based BPS criteria elements.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments: Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | James H. Sorrels, Jr. | |
| Organization: | American Electric Power | |
| Telephone: | (614) 716-2370 | |
| E-mail: | jhsorrels@.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☒ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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- **Associated Documents**
  The drafting team added a section “F” to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: We believe that the RC should work in conjunction with the Bulk Electric System owners and operators to help make the determination.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

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   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments:

   We believe that the appropriate violation severity level designation for the violation described in Section D-2.2.1 should be "Lower" rather than "Moderate". The language in D-2.2.1 and D-2.4.1 is ambiguous and should include references to the specific requirements that apply.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☐ No unnecessary adverse impacts

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   ☐ No field testing is necessary

   ☒ Field testing is necessary

   Comments: While field testing may be difficult for PRC-023, it would be useful to provide a transition period wherein violations are reviewed, but not subject to sanction or fine.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: In response to question 4 above (there is no comment space provided), it is difficult to assess this impact on energy markets without having had the standard deployed.  The referenced field test (or transition period) would be beneficial to make such a determination.

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Group Comments (Complete this page if comments are from a group.)

**Group Name:** SERC Protection and Control Subcommittee (PCS)

**Lead Contact:** Jay Farrington

**Contact Organization:** Alabama Electric Cooperative, Inc.

**Contact Segment:** 1

**Contact Telephone:** (334) 427-3225

**Contact E-mail:** jay.farrington@powersouth.com

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Robert Rauschenbach | Ameren | SERC | 1 |
| Sonia Walden | Dominion Virginia Power | SERC | 1 |
| Paul Smith | Duke Energy Carolinas | SERC | 1 |
| Charlie Fink | Entergy | SERC | 1 |
| Tom Seeley | E.ON-U.S. | SERC | 1 |
| Phil Winston | Georgia Power Company | SERC | 1 |
| Steve Waldrep | Georgia Power Company | SERC | 1 |
| Hong-Ming Shuh | Georgia Transmission Corporation | SERC | 1 |
| Eithar Nashawati | Progress Energy Carolinas | SERC | 1 |
| Jerry Blackley | Progress Energy Carolinas | SERC | 1 |
| Pat Huntley | SERC Reliability Corp. | SERC | 10 |
| Marion Frick | South Carolina Electric & Gas Company | SERC | 1 |
| Bridget Coffman | South Carolina Public Service Authority | SERC | 1 |
| George Pitts | Tennessee Valley Authority | SERC | 1 |
| Meyer Kao | Tennessee Valley Authority | SERC | 1 |
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   ☐ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☐ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

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   ☐ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: 1. R4 should have provisions for temporary and technical exceptions on newly identified critical circuits. 2. The implementation dates in 5.1.2 and 5.2 needs to be clarified. For the initial list, the 39 month clock should start after the RC designates a circuit as critical.

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
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| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:** Public Service Commission of South Carolina

**Lead Contact:** Phil Riley

**Contact Organization:** Public Service Commission of South Carolina

**Contact Segment:** 9

**Contact Telephone:** 803-896-5154

**Contact E-mail:** philip.riley@psc.sc.gov

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mignon L. Clyburn | Public Service Commission of SC | SERC | 9 |
| Elizabeth B. Fleming | Public Service Commission of SC | SERC | 9 |
| G. O'Neal Hamilton | Public Service Commission of SC | SERC | 9 |
| John E. Howard | Public Service Commission of SC | SERC | 9 |
| Randy Mitchell | Public Service Commission of SC | SERC | 9 |
| C. Robert Moseley | Public Service Commission of SC | SERC | 9 |
| David A. Wright | Public Service Commission of SC | SERC | 9 |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background Information**

The Relay Loadability standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The standard and implementation plan were modified in response to the comments.

In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
  - ***Same-day Operations****:* routine actions required within the time frame of a day, but not real-time.
  - ***Real-time Operations****:* actions required within one hour or less to preserve the reliability of the Bulk Electric System.
  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted "levels of non-compliance" and added "violation severity levels" to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
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- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments:

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

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   ☒ I agree with the Violation Severity Levels.

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   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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   ☐ No field testing is necessary

   ☒ Field testing is necessary

   Comments: The PSCSC believes field testing is necessary, since NERC is significantly expanding the scope of facilities to which this standard will apply.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☒ No additional comments

   Comments:

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**

| | |
|---|---|
| Name: | Richard J Pienkos |
| Organization: | Consumers Energy Company |
| Telephone: | (517) 788-0550 |
| E-mail: | rjpienkos@cmsenergy.com |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☐ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs and ISOs |
| ☐ MRO | ☒ | 3 — Load-serving Entities |
| ☐ NPCC | ☒ | 4 — Transmission-dependent Utilities |
| ☒ RFC | ☒ | 5 — Electric Generators |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☒ Yes

   ☐ No

   Comments:

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   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

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   Comments:

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   ☐ No additional comments

   Comments: 1. Section 2.4.1, the word "thought" should be "through". 2. This standard is extremely difficult to understand and apply without the use of PRC-23 Reference Guide. This guide is very helpful in understanding what is being suggested and where the margins come from. However, it fails to give any guidance for criteria R1.13. Some examples or suggestions on how to use this criteria would be most helpful. Also, while the PRC-23 Reference Guide is listed as an "Associated Document" in Section F, it would seem helpful to mention this reference guide earlier in the standard (possibly as a note) as its use is important to correct application of these criteria.

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**Individual Commenter Information**

**(Complete this page for comments from one organization or individual.)**


| | |
|---|---|
| Name: | Robert Coish |
| Organization: | Manitoba Hydro |
| Telephone: | (204) 487-5479 |
| E-mail: | rgcoish@mb.ca |


| **NERC Region** | | **Registered Ballot Body Segment** |
|---|---|---|
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   ☒ Yes

   ☐ No

   Comments: However, the Reliability Coordinator should coordinate on the methodology to identify critical facilities with the Transmission Owners. Also, this procedure to identify critical facilities should be coordinated with the procedure to identify critical assets in the Critical Infrastructure Protection Standards (CIP-002-1) to avoid potential confusion or conflict (i.e. two similar lists developed by different procedure).

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments: Before we can comment on the appropriate assignment of Mitigation Time Horizons we need a better explanation of the concept of Mitigation Time Horizons and how Mitigation Time Horizons will be used to determine sanctions. MH appreciates the consideration of comments response on the Mitigation Time Horizon issue from the Balance Resources and Demand SDT. However their response does not sufficiently address our concerns. It would be helpful for stakeholder consideration of assignment of Mitigation Time Horizons, MH suggests, if NERC could post a clear proposed definition of the term Mitigation Time Horizon and provide a fuller explanation of intended use to determine the size of sanctions. We gather that the concept is that violations involving more immediate or real-time activities will generally incur larger panalties than violations involving longer time frames. This is very vague. The suggested posting could serve as a draft addition to the Reliability Standards Development Procedure. Neither the comments in this form nor the ERO Rules of Procedure provide a definition or sufficient explanation. The term "Mitigation Time Horizon" does not appear in the Rules of Procedure or any other NERC document as far as we know. The term "Violation Time Horizon" on the Rules of Procedure is obviously related.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a

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Comments:

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   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☒ No field testing is necessary

☐ Field testing is necessary

Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments: See below:

A.3.

The word "Transmission loadability" need to be clearly defined/clarified.

Suggested wording:

1. Protective relay settings shall not limit transmission loadability which was determined by regional approved operating guidelines.

2. Protective relay settings shall not limit practical loading capability of a circuit

A. 4.2

Who is to ensure that the IPPs(generator owners) will comply with this standard?

B. R1.1.

“The highest seasonal Facility Rating of a circuit” is not clearly defined in this draft of the standard. It has been changed from the original term of “Emergency Ampere Rating” of a circuit

Does this imply that the highest possible loading limit (which could be lower than the thermal rating) of a circuit can be used as the highest seasonal Facility Rating?

B. R1.10 and R1.11

How to distinguish transformer fault protection relays from overload protection relays?

On R1.11, if overload protection is desired, can we add a phase overcurrent relay with a definite time delay of not less than 15 minutes, regardless of trip setting?

R1.11, the transformer overload relays must not trip at 150% of the maximum applicable nameplate rating. Does this mean the MVA rating of the transformer? Considering the need to evaluate loadability at 0.85 pu voltage, does this imply a requirement to set overcurrent relays at 165%?

B. R1.13

Manitoba Hydro appreciates the SDT adding this option which addresses our concern about being able to use stability limits as the maximum rating of a circuit.

We are curious to know, if we have a hard limit on the circuit, why is it nessesary to add another 15% on this limitation? For example, we have transformers which the manufacturer has subsequently advised us to restrict operation such that there is no loading above the continuous loading. In this case, being forced to add a margin would only subject the transformer to potential failure.

I believe that this could be written such that the aim would be to have a 15% margin unless there was evidence that equipment damage would occur.

B. In general Mantioba Hydro does not have major concerns with R2 but would like the SDT to consider two suggestions which we believe would add value to R2 specifically as it applies to R1.13.

Manitoba Hydro see the benefit in getting agreement between the Transmission Operator, the Planning Authority, and the Reliability Coordinator in developing limits. In some areas Mantioba Hydro would agree that this should be adequate. However areas that are close to a seam in any of these functions (TO, PA, or RC) should be seeking greater stakeholder approval.

Manitoba Hydro suggest that this could be accomplished by having the entitiy publish an operating guide for the facility in question. An operating guide would require the entity to seek further stakeholder input, and would still require, thorough other NERC standards, the approval of the appropriate functions under the NERC functional model.

The second concern is in the approval of ratings. In some jurisdictions, Mantioba is one, ratings which are different for the nameplate ratings would have to have the approval of a Professional Engineer with the right to practice within that jurisdiction. This is required because there is a safety issue regarding the operation of the equipment. This calls into question the legality of requiring various function under the NERC model to aprove (or agree with ratings) unless they have the legal right to set that rating.

Mantioba Hydro would suggest that name plate ratings should always be considered as appropriate limits. However when nameplate limits cannot be used for any reason, the entity owning the equipment will submit a notice, sealed by a Professional Engineer with the right to practice within the jurisdiction that the equipment resides, informing the TO, PA, and the RC why the nameplate ratings cannot be used and advising the variuos functions of the new ratings. The standard writing team should remember that a Professinal Engineer has a legal responsibility to stakeholders beyond the firm for which they practice, and that obligation should provide the independence sought for in this requirement. It also has the benefit of avoiding the potential situation where the TO, PA, and RC do not agree on a proposed rating.

C.

What would be considered as acceptable evidence?

Attachment A

2.

A word PERMANENTLY should be added before “block trip...”?

3.3

I am not quite sure what exactly this mean?

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| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

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| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of "Mitigation Time Horizons" as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
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  - ***Same-day Operations****:* routine actions required within the time frame of a day, but not real-time.
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  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

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  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
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- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☒ No

   Comments: For the existing system, HQT believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level. An approved Regional performance based methodology should be used to consistently determine this on a wide area basis. The same could apply for the Planning Authority/Coordinator for future equipment additions since the relay settings would be done during project development.
   However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize the Drafting Team's critera.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☒ I agree with the proposed Mitigation Time Horizons.

   ☐ I do not agree with the following Mitigation Time Horizons.

   Comments:

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: (1) Section D 2.4.1 should be changed to read as follows, to correspond with B R.1 and to correct an error: "Relay settings do not comply with at least one of R

1.1 though R 1.13, or evidence does not exist to support that relay settings comply with at least one of R 1.1 through R 1.13.

(2) Section D, 3.3.1 (Reliability Coordinator does not provide the list....) should be moved to the Severe level, 3.4.2 (Reliability Coordinator does not maintain a current list of facilities....) should be moved to the High level.

From our perspective there are 3 key elements in establishing the list of facilities critical to the reliability of the bulk electric system: 1) determining the facility list, 2) communicating the list to asset owners, and 3) maintaining the list.

The intent of R3 is to ensure that facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating the list of critical facilities is, in our view, one of the most important requirements, and there is no partial communicating so it's a case of either full compliant or flat out non-compliant. We therefore propose that 3.3.1 be moved to the Severe level.

If we accept the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does imply that the list has been communicated to the facility owners, and the requirement to maintain the list can be partially met. On the other hand, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 (Reliability Coordinator does not maintain a current list of facilities..) be moved to the High level.

Determining which facilities are critical to the reliability of the electric system is also an important first step. We agree that 3.4.1 should be retained at the Severe level, but propose to revise the sentence to read: "Reliability Coordinator does not have a process in place to determine, or evidence that it has determined, facilities that are critical to the reliability of the electric system."

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

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5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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☐ No field testing is necessary

☒ Field testing is necessary

Comments: HQT believe the need for further field testing depends on the outcome of the final determination of what constitutes the BPS. Additional time or effort for field testing may be required to not only come into compliance if large additional portions of the lower voltage electric system are included, but to test the validity and coordination of the concepts contained in this standard. During NERC SPCTF's previous efforts pertaining to Beyond Zone 3 the application of the concepts were somewhat confined.

HQT believe the Standard as written should not be restricted to voltage classifications and should be applied to performance based BPS criteria elements.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments: Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus.

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| **Individual Commenter Information** (Complete this page for comments from one organization or individual.) | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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   Comments:

   (1) Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13. We find this confusing, and does not correspond to R1, which says:

   "Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent …" We interpret this to mean that an entity is compliant if it meets at least one of the criteria listed in R1 through R1.13.

To add clarity to the text, we suggest rewording D 2.4.1 as follows:

"Relay settings do not comply with at least one of R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with at least one of the criteria in R1.1 through R1.13."

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☒ No field testing is necessary

☐ Field testing is necessary

Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments:

VRFs are now an integral part of the standards, which as a whole, require industry consensus for development and approval. Yet, there is no question asked on the concurrence on the violation risk factor levels for this draft, despite the fact that there are now new requirements assigned to the Reliability Coordinators. Is it an oversight, or is it an assumption that the assigned VRFs are acceptable to the industry?

In either case, we feel strongly that this question should be asked in order to provide the SDT an assessment of the acceptability of the assigned risk levels, although we do not disagree with any of the assigned risk levels.

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| **Individual Commenter Information** | | |
|---|---|---|
| **(Complete this page for comments from one organization or individual.)** | | |
| Name: Mark Kuras | | |
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| **NERC Region** | | **Registered Ballot Body Segment** |
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**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

## Background Information

The Relay Loadability standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The standard and implementation plan were modified in response to the comments.

In addition, a new version of the Reliability Standards Development Procedure was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised procedure or other changes needed to conform to the ERO Rules of Procedure:

- **Mitigation Time Horizons**
  The ERO Rules of Procedure include the use of “Mitigation Time Horizons” as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing Mitigation Time Horizons for each requirement:

  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
  - ***Same-day Operations****:* routine actions required within the time frame of a day, but not real-time.
  - ***Real-time Operations****:* actions required within one hour or less to preserve the reliability of the Bulk Electric System.
  - ***Operations Assessment***: follow-up evaluations and reporting of real-time operations.

- **RRO as Responsible Entity**
  The drafting team modified all requirements to eliminate the Regional Reliability Organization as the responsible entity, and replaced these references with the appropriate entity.

- **Levels of Non-compliance Versus Violation Severity Levels**
  The drafting team deleted “levels of non-compliance” and added “violation severity levels” to comply with the revised Reliability Standard Development Procedure. Compliance personnel assisted the drafting team in using the following criteria from the procedure to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- ***Severe:*** poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**
  The drafting team added a section "F" to the standard called, References.

You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☐ Yes

   ☒ No

   Comments: Planning Coordinators would be better suited to determine critical facilities. I don't like the use of this concept without a defdinition or process put forth to extablish this critical circuits idea. Will a compliance review be performed on my determination of criticality of circuits? Will I be second guessed by a NERC auditor if I say I have no critical lines?

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: Not sure what they mean in relation to a determination of non-compliance and the associated penaties.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☒ I agree with the Violation Severity Levels.

   ☐ I do not agree with the following Violation Severity Levels.

   Comments:

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

☒ No unnecessary adverse impacts

☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

   Transmission Owners, applicable Generator Owners, and applicable Distribution Providers, collectively referred to in the activities cited above as "Transmission Protection System Owners," or "TPSOs," have certified, through their respective Regions, that they have reviewed all of their load responsive relays in accordance with the specifications in those activities, and, in the case of the previous activity, have cited that they have completed the changes necessary to conform to those specifications. These certifications have been reviewed both by the respective Regions and by the NERC System Protection and Control Task Force; summary reports of these reviews have been approved by the NERC Planning Committee and have been presented to the NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

   The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

   ☒ No field testing is necessary

   ☐ Field testing is necessary

   Comments:

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

   ☐ No additional comments

   Comments: In R1.5, weak-source systems needs to be defined. In R1.6, remote to load needs to be defined. In R1.7 remote from generation stations and load center terminal needs to be defined. in R1.8 and R1.9, remote to the system needs to be defined. In R1.11, highest opertor established should be highest owner established. All instances of Reliability Coordinator in R3 and R4 should be changed to Planning Coordinator.

Please use this form to submit comments on the proposed Relay Loadability standard. Comments must be submitted by **February 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with "**Relay Loadability"** in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☐ | 5 — Electric Generators |
| ☐ **SERC** | ☐ | 6 — Electricity Brokers, Aggregators, and Marketers |
| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 - Regional Reliability Organizations; Regional Entities |

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| Group Comments (Complete this page if comments are from a group.) | |
| **Group Name:** | Midwest Reliability Organization |
| **Lead Contact:** | Tom Mielnik |
| **Contact Organization:** | MRO for Group (MidAmerican for Contact) |
| **Contact Segment:** | 10 |
| **Contact Telephone:** | (563) 333-8129 |
| **Contact E-mail:** | TCMielnik@midamerican.com |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPSR | MRO | 10 |
| Terry Bilke | MISO | MRO | 10 |
| Al Boesch | NPPD | MRO | 10 |
| Robert Coish, Chair | MHEB | MRO | 10 |
| Carol Gerou | MP | MRO | 10 |
| Ken Goldsmith | ALT | MRO | 10 |
| Todd Gosnell | OPPD | MRO | 10 |
| Jim Haigh | WAPA | MRO | 10 |
| Pam Oreschnik | XEL | MRO | 10 |
| Dick Pursley | GRE | MRO | 10 |
| Dave Rudolph | BEPC | MRO | 10 |
| Eric Ruskamp | LES | MRO | 10 |
| Joe Knight, Secretary | MRO | MRO | 10 |
| 27 Additional MRO Members | Not Named Above | MRO | 10 |
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- **Associated Documents**
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You do not have to answer all questions.

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?

   ☒ Yes

   ☐ No

   Comments: The standard does not appear to require the Reliability Coordinator to do this in conjuncton with the other Applicable Entities. R3.1.1 states This process shall include coordination with adjoining Reliability Coordinator(s). The MRO recommends that this requirement be expanded to include the other Applicable Entities listed in this standard.

   The critical facilities list required by this standard, should be coordinated with the critical facilities lists required by other standards in as much as it it possible.

2. The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement.

   Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.

   ☐ I agree with the proposed Mitigation Time Horizons.

   ☒ I do not agree with the following Mitigation Time Horizons.

   Comments: Mitigation Time Horizons are described near the top of this comment form.

   The description of the Mitigation Time Horizons states The ERO Rules of Procedure include the use of mitigation time horizons as one element used to determine the size of sanctions.

   Can the drafting team inform the Registered Ballot Body where the ERO definition of Mitigation Time Horizons can be found along with documentation describing how the mitigation time horizons will be used in determining penalties. Mitigation Time Horizons are not listed as a Performance Element of a Reliability Standard in the Reliability Standards Development Procedure Version 6 adopted by the NERC BOT on November 1, 2006. As such, it does not seem appropriate to include them in any Reliability Standards.

   The comment form description of Mitigation Time Horizons further states The drafting team used the following guidelines in developing mitigation time horizons for each requirement, whereas the final statement in the description of the Violation Risk Factors states The following categories of violation risk factors were approved with the latest version of the Reliability Standards Development Procedure. Like the Violation Risk Factors, the categories of Mitigation Time Horizons should also be approved and incorporated into the Reliability Standards Development Procedure in order to ensure that the definitions are consistent for all NERC Reliability Standards.

The MRO cannot vote to approve a standard that includes Mitigation Time Horizons until the drafting team can produce ERO documented definitions and the documented manner in which the Mitigation Time Horizons will be used to determine penalties.

3. The latest version of the Reliability Standards Development Procedure requires that each standard include “Violation Severity Levels” rather than “levels of non-compliance.” “Violation Severity Levels” identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the “Violation Risk Factor” appended to each requirement.)

   Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

   ☐ I agree with the Violation Severity Levels.

   ☒ I do not agree with the following Violation Severity Levels.

   Comments: The MRO does not agree with the proposed Violation Severity Levels due to the fact that they have not been fully vetted in the Standards Development Process. A process which includes being held up for public comment, scrutiny and balloting.

4. Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.

   ☒ No unnecessary adverse impacts

   ☐ Unnecessary adverse impact on markets

5. One previous NERC activity and one ongoing activity, both outside the compliance process, have addressed relay loadability. The previous activity has essentially been completed. It was based on NERC Recommendation 8a (resulting from the investigation into the August 14, 2003 blackout) and addressed zone 3 relays on transmission lines, 200 kV and above. The ongoing activity, "Protection System Review Program — Beyond Zone 3" addresses all other load-responsive relays at 200 kV and above, and on "operationally significant circuits, 100 kV–200 kV", and should be essentially completed by 12/31/08. Both activities were approved in detail by the NERC Planning Committee and by the NERC Board of Trustees. The requirements of PRC-023, together with the added information in the PRC-023 Reference Document, were drafted from the specifications of these activities.

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NERC Board of Trustees. These summary reports may be found at www.nerc.com, under Committees — Planning Committee — System Protection and Control Task Force — Related Files.

The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?

☐ No field testing is necessary

☒ Field testing is necessary

Comments: The MRO believes that field testing is necessary so as to gauge if the time being allotted to the operators to respond is appropriate and to make sure the equipment is reasonably protected.

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

☐ No additional comments

Comments: Several companies in the MRO use line ratings of other than 4 hours. The MRO recommends the addition of a conversion factor for those companies using emergency ratings not consistent with what is stated in the standard. In lieu of a conversion factor, a standard line rating issued by NERC would be acceptable.

The MRO is concerned about what appears to be the forced assumption of risk with respect to overload levels and time durations that said overloads must be held. The MRO believes that it should be up to the Transmission Owner to determine the amount of risk they are willing to assume based on their own risk analysis.

In the Measures section under M3, the applicable entities listed for which the list of critical facilities must be provided to is not consistent with the applicable enities listed in R3 which M3 refers.

In the Violation Severity section, under violations for TOs, GOs, and DPs the definition of a Severe Violation is not complete.

The MRO is concerned that this standard is removing some inherent thermal overload protection from the bulk electric system. In its response to comments the SAR drafting team stated - The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides, admittedly crude, overload protection and MRO believes there is increased inherent risk to the bulk electric system in the sentiment of the SAR drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? The MRO believes that a risk analysis should be conducted before implementing this standard.

The MRO believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with regard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive.

If during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wave traps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of service on time?

The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RROs are required to make this designation should be recommended by the SDT and added to the implementation plan. 2. Regarding the implementation plan, one would have expected an implementation time frame of the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven months after establishment of the standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC is depending on all participants to have proceeded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did?

The MRO feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event.

The MRO has a concern with the 15 percent additional margin applied to the facility rating. This can be considered a negative margin with regard to protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy.

Does this standard expose the TO etc. to legal risk if there is damage to the public, violating vertical clearances for example?

If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems, (not to mention the human involvement, designed and maintained with equivalent reliability to the protection system? Also, the SCADA system may be down therefore the operator may not be able to assume the role of preventing equipment damage.

There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 p.u. voltage and power factor angle of 30 degrees criteria may not be appropriate for all cases.

This standard removes the option of using zone three relays to provide more reliable system operation a. For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. Moving blinders in may make it impossible to detect fast moving swings. b. On interties: It may not be possible to set relays to detect the fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur.

This standard seems to be precluding the concept of TOs etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system.

In M1 and M2 it should be further clarified what is meant by evidence.

The draft standard states the "The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers." But for what scenario or number of contingencies is this statement accurate? If a study is conducted to show that the 150% setting for zone 3 is not necessary, and the Transmission Owner wants to protect equipment with a more appropriate trip setting of say 125 percent, would the Transmission Owner have to prove that the setting is good for Category C for example; the Category C is listed in our question because the Transmission Owner typically is required only to plan for Category D only when the risk and consequences indicates there is a need to plan for such an event? The Transmission Owner can always come up with scenarios of contingencies that will trip a line or transformer, even at the 150 percent setting and not allow the operator time to react. Should the four hour rating be replaced with a one hour rating given that the four hour rating may be used to allow operator action rather than require relay or automatic control actions to remove a disturbance in a more timely fashion?

The Relay Loadability Standard Drafting Team and the Compliance Elements Drafting Team both thank all commenters who submitted comments on the Draft 2 of the Reliability Loadability standard. This standard was posted for a 30-day public comment period from January 2 through February 7, 2007. The Relay Loadability Standard Drafting Team and Compliance Elements Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 22 sets of comments, including comments from more than 93 different people from more than 66 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on stakeholder comments, the drafting team revised the effective dates to provide more time to apply relay settings for switch-on-to-fault schemes:

- For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
- For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.

Based on stakeholder comments and a review of the latest version of the Functional Model, the drafting team revised Requirement 3 to read as follows:

- The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kv to 200 kv that must meet Requirement 1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

This change re-assigns responsibility for making the determination of the facilities critical to the reliability of the BES from the Reliability Coordinator to the Planning Coordinator. Because this task is performed in the 'long-term planning' time frame, this task should be assigned to the Planning Coordinator.

The Compliance Elements Drafting Team made modified the violation severity levels in response to stakeholder comments. The CEDT modified violation severity level for failure to meet Requirement 1 by adding the word 'any' to clarify that the relay settings do not need to meet 'all' of he requirements in R1.1, just 'any' one of the settings. The revised language states:

- Relay settings do not comply with any of the requirements in R1.1 through R1.13.

The CEDT also added more specificity to the violation severity levels for failure to distribute the list of critical facilities within 30 days of the list's initiation or update. If the list was provided between 31 – 45 days this is a moderate violation; if the list was provided between 46 to 60 days, this is a High violation – and if the list was not provided or was provided after more than 60 days, this is now a 'Severe' violation. (The moderate and severe violation levels are new and the high level was modified by adding timeliness.)

Based on stakeholder comments, the drafting team added the following to the list of exceptions in Attachment A of the standard:

- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings

The drafting team is recommending that the Standards Committee authorize moving these standards forward.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Relay-Loadability.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Jay Farrington | Alabama Electric Cooperative, Inc. | ✓ | | | | | | | | | |
| 2. | Ben Pilleteri | Alabama Power Company | ✓ | | | | | | | | | |
| 3. | Dan Shield | Alberta Electric System Operator | ✓ | | | | | | | | | |
| 4. | Anita Lee | Alberta Electric System Operator | | ✓ | | | | | | | | |
| 5. | Ken Goldsmith | ALT | | | | | | | | | | ✓ |
| 6. | Robert Rauschenbach | Ameren | ✓ | | | | | | | | | |
| 7. | James Sorrels, Jr. | American Electric Power | ✓ | | | | ✓ | ✓ | | | | |
| 8. | Randy Spacek | Avista Corp. | ✓ | | | | | | | | | |
| 9. | Dave Rudolph | BEPC | | | | | | | | | | ✓ |
| 10. | Dean Bender | Bonneville Power Administration | ✓ | | | | | | | | | |
| 11. | Alan Gale | City of Tallahassee | | | | | ✓ | | | | | |
| 12. | Ed Thompson | Con Edison | ✓ | | | | | | | | | |
| 13. | Richard J Pienkos | Consumers Energy Company | | | ✓ | ✓ | ✓ | | | | | |
| 14. | Carl Kinsley | Delmarva Power & Light Company | ✓ | | | | | | | | | |
| 15. | Sonia Walden | Dominion Virginia Power | ✓ | | | | | | | | | |
| 16. | Paul Smith | Duke Energy Carolinas | ✓ | | | | | | | | | |
| 17. | Tom Seeley | E.ON-U.S. | ✓ | | | | | | | | | |
| 18. | Charlie Fink | Entergy | ✓ | | | | | | | | | |
| 19. | Ed Davis | Entergy Services, Inc. | ✓ | | | | | | | | | |
| 20. | Eric Senkowicz | Florida Reliability Coordinating Council | | ✓ | | | | | | | | |
| 21. | Linda Campbell | Florida Reliability Coordinating Council | | ✓ | | | | | | | | |
| 22. | Mark Bennett | Gainesville Regional Utilities | | | | | ✓ | | | | | |
| 23. | Phil Winston | Georgia Power Company | ✓ | | | | | | | | | |
| 24. | Phil Winston | Georgia Power Company | ✓ | | | | | | | | | |
| 25. | Steve Waldrep | Georgia Power Company | ✓ | | | | | | | | | |
| 26. | Hong-Ming Shuh | Georgia Transmission Corporation | ✓ | | | | | | | | | |
| 27. | Dick Pursley | GRE | | | | | | | | | | ✓ |
| 28. | Steve Carter | Gulf Power Company | ✓ | | | | | | | | | |
| 29. | Roger Champagne | Hydro Quebec TransEnergie | ✓ | | | | | | | | | |
| 30. | Ron Falsetti | IESO | | ✓ | | | | | | | | |
| 31. | Kathleen Goodman | ISO- New England | | ✓ | | | | | | | | |
| 32. | Bill Shemley | ISO-New England | | ✓ | | | | | | | | |
| 33. | Brian Thumm | ITC Transmission | ✓ | | | | | | | | | |
| 34. | Eric Ruskamp | LES | | | | | | | | | | ✓ |
| 35. | Donald Nelson | MA. Dept of Tele. and Energy | | | | | | | | | ✓ | |
| 36. | Robert Coish | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 37. | Tom Mielnik | MidAmerican | | | | | | | | | | ✓ |
| 38. | Joe Knight | Midwest Reliability Organization | | | | | | | | | | ✓ |
| 39. | Terry Bilke | MISO | | | | | | | | | | ✓ |
| 40. | Joseph Stewart | Mississippi Power Company | ✓ | | | | | | | | | |
| 41. | Carol Gerou | MP | | | | | | | | | | ✓ |
| 42. | Herb Schrayshuen | National Grid | ✓ | | | | | | | | | |
| 43. | Greg Campoli | New York ISO | | ✓ | | | | | | | | |
| 44. | Ralph Rufrano | New York Power Authority | ✓ | | | | | | | | | |
| 45. | Brian Hogue | Northeast Power Coordinating Council | | | | | | | | | | ✓ |
| 46. | Guy Zito | Northeast Power Coordinating Council | | | | | | | | | | ✓ |
| 47. | Murale Gopinathan | Northeast Utilities | ✓ | | | | | | | | | |
| 48. | Al Boesch | NPPD | | | | | | | | | | ✓ |
| 49. | Jerad Barnhart | NSTAR | ✓ | | | | | | | | | |
| 50. | David Kiguel | Ontario Hydro | ✓ | | | | | | | | | |
| 51. | Todd Gosnell | OPPD | | | | | | | | | | ✓ |
| 52. | Ben Morris | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 53. | Chifong Thomas | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 54. | Ed Taylor | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 55. | Glenn Rounds | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 56. | Tom Siegel | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 57. | Vahid Madani | Pacific Gas & Electric | ✓ | | | | | | | | | |
| 58. | Richard J. Kafka | Pepco Holdings, Inc. Affiliates | ✓ | | | | | | | | | |
| 59. | Mark Kuras | PJM | | ✓ | | | | | | | | |
| 60. | Alvin Depew | Potomac Electric Power Company | ✓ | | | | | | | | | |
| 61. | Evan Sage | Potomac Electric Power Company | ✓ | | | | | | | | | |
| 62. | Eric Grant | Progress Energy – Florida | ✓ | | | | | | | | | |
| 63. | D. Bryan Guy | Progress Energy Carolina, Inc. | ✓ | | ✓ | | ✓ | | | | | |
| 64. | Eithar Nashawati | Progress Energy Carolinas | ✓ | | | | | | | | | |
| 65. | Jerry Blackley | Progress Energy Carolinas | ✓ | | | | | | | | | |
| 66. | C. Robert Moseley | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 67. | David A. Wright | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 68. | Elizabeth B. Fleming | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 69. | G. O'Neal Hamilton | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 70. | John E. Howard | Public Service Commission of South Carolina | | | | | | | | | ✓ | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 71. | Mignon L. Clyburn | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 72. | Phil Riley | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 73. | Randy Mitchell | Public Service Commission of South Carolina | | | | | | | | | ✓ | |
| 74. | Dick Curtner | Public Service of New Mexico | ✓ | | | | | | | | | |
| 75. | Malkiat Dhillon | Sacramento Municipal Utility District | ✓ | | | | | | | | | |
| 76. | Jonathan Sykes | Salt River Project | ✓ | | | | | | | | | |
| 77. | Pat Huntley | SERC Reliability Corp. | | | | | | | | | | ✓ |
| 78. | Gene Henneberg | Sierra Pacific Power Company | ✓ | | | | | | | | | |
| 79. | Marion Frick | South Carolina Electric & Gas Company | ✓ | | | | | | | | | |
| 80. | Bridget Coffman | South Carolina Public Service Authority | ✓ | | | | | | | | | |
| 81. | J.T. Wood | Southern Co. Transmission | ✓ | | | | | | | | | |
| 82. | Jim Busbin | Southern Co. Transmission | ✓ | | | | | | | | | |
| 83. | Marc Butts | Southern Co. Transmission | ✓ | | | | | | | | | |
| 84. | Roman Carter | Southern Co. Transmission | ✓ | | | | | | | | | |
| 85. | Charles Sufana | Sufana Engineering, Inc. | | | | | | | | ✓ | | |
| 86. | George Pitts | Tennessee Valley Authority | ✓ | | | | | | | | | |
| 87. | Meyer Kao | Tennessee Valley Authority | ✓ | | | | | | | | | |
| 88. | Bill Middaugh | Tri-State Gen. and Trans. Ass'n. | ✓ | | | | | | | | | |
| 89. | Jim Haigh | Western Area Power Administration | | | | | | | | | | ✓ |
| 90. | Paul Rice | Western Electricity Coordinating Council | ✓ | | | | | | | | | |
| 91. | Neal Balu | WPSR | | | | | | | | | | ✓ |
| 92. | Mike Ibold | Xcel Energy | ✓ | | | | | | | | | |
| 93. | Pam Oreschnik | XEL | | | | | | | | | | ✓ |

## Index to Questions, Comments, and Responses

1. **The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?**

**Summary Consideration:** After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. and to require that the Planning Coordinator's process for identifying the critical facilities include input from adjoining Planning Coordinators and affected Reliability Coordinators. Determination of facilities critical to reliability of the Bulk Electric system is performed in the long-term planning time frame. The drafting team feels that assigning this requirement to the Planning Coordinator is consistent with the responsibilities of the Planning Coordinator defined in the Functional Model. The drafting team also added language to the requirement to clarify that the Planning Coordinator's process for identifying critical facilities must include input from adjoining Planning Coordinators and affected Reliability Coordinators.

The drafting team also modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in this standard is not the same as the Critical Infrastructure standards and would not be expected to result in the same list of facilities.

| **Question #1** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| PJM | | ☑ | Planning Coordinators would be better suited to determine critical facilities. I don't like the use of this concept without a defdinition or process put forth to extablish this critical circuits idea. Will a compliance review be performed on my determination of criticality of circuits? Will I be second guessed by a NERC auditor if I say I have no critical lines? |
| **Response:** Determination of facilities critical to reliability of the Bulk Electric system is performed in the long-term planning time frame and is consistent with the responsibilities of the Planning Coordinator defined in the Functional Model. For that reason, the drafting team did modify the standard to assign this requirement to the Planning Coordinator.<br><br>The measure only requires that there be a methodology and that the list resulting from that methodology be provided to the listed entities. There is no measure of the quality of the methodology. | | | |
| Entergy Services, Inc. | | ☑ | We think the RC should not be the exclusive determinator of - critical to the reliability of the BES -, especially since the other entities are required to expend resources to comply with that determination. Therefore, we suggest the responsible entites under R3 be changed from - RELIABILITY COORDINATOR SHALL DETERMINE - to - RELIABILITY COORDINATOR, IN |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | CONJUNCTION WITH TRANSMISSION OWNERS, GENERATION OWNERS, AND DISTRIBUTION PROVIDERS SHALL DETERMINE. This change should be made in R3, along with our suggested change to the Appicability comment in response to Question 6 below. |
| **Response:** Determination of facilities critical to reliability of the Bulk Electric system is performed in the long-term planning time frame and is consistent with the responsibilities of the Planning Coordinator defined in the Functional Model. According to V3 of the Functional Model, the Planning Coordinator is responsible for the coordination suggested in your comment. | | | |
| Alberta Electric System Operator - AESO | | ☑ | The WECC currently maintains the bulk transfer path catalog which provides a list of the critical facilities. It may be more appropriate for the RRO to be the entity responsible for making the determination on critical facilities. |
| **Response:** In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator. | | | |
| Western Electricity Coordinating Council | | ☑ | The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO. |
| **Response:** In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator. | | | |
| Florida Reliability Coordinating Council | | ☑ | The shift from RRO to RC accountability for determination of "circuits critical to the reliability of the Bulk Electric System" is a significant step change in current NERC Reliability philosophy. One concern we have is for consistency across the Regions and the change in this standard would shift that concern to consistency across RCs of the Interconnections.<br><br>The second concern is that this will effectively shift some of the RC functions and accountabilities over to a role as a Compliance monitor. Some of the compliance elements associated with the new RC relationships may create inadvertent coordination and compliance measuring conflicts between the new Regional Entities, the RCs and the transmission owners that will ultimately have to comply with PRC-023. |

| Question #1 | | | |
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| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Based on the above we recommend removal of the RC related requirements and applicabilities until NERC (as the ERO) can better define the criteria or methodology for determining "circuits critical to the reliability of the Bulk Electric System" or establish a standardized Rliebility Impact Based methodology for RCs to use when creating the critical circuits list (circuits between 100 kV and 200 kV). |
| **Response:** In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator.<br>There is nothing in the standard that assigns the Reliability Coordinator (now Planning Coordinator) any compliance monitoring responsibilities. | | | |
| American Electric Power | | ☑ | We believe that the RC should work in conjunction with the Bulk Electric System owners and operators to help make the determination. |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. The drafting team also included a requirement that the Planning Coordinator consider inputs from the Reliability Coordinator within the process. | | | |
| Progress Energy Carolina, Inc. | | ☑ | Not as written. Requirement 3.1 requires that the RC have a process to determine critical 100-200kV lines that must meet relay loadability requirements. Req 3.1.1 requires that the RC coordinate with adjoining RCs.<br>The standard should also include a provision, Req 3.1.2, that requires the RC process to also coordinate with the facility Transmission Owner(s) in addition to the adjoining RCs. |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. The drafting team also included a requirement that the Planning Coordinator consider inputs from the Reliability Coordinator within the process. | | | |
| Northeast Power Coordinating Council | ☑ | ☑ | NPCC participating members believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level and an approved Regional performance based methodology should be used to consistently determine this on a wide area basis. However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | the Drafting Team's critera. |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator considering inputs from the Reliability Coordinator.<br>For the purpose of this standard it is only necessary that the Planning Coordinators determine circuits critical to the reliability of the Bulk Electric System. While some Planning Coordinators may not yet have a documented process, the standard does require the responsible entity to have a documented process – this is not an option.<br>The definition of bulk power systems vary from region to region. For the consistent application of this standard all facilities 200kV and above are included, as well as facilities 100kV and above that are deemed "critical to the reliability of the bulk power system". | | | |
| IESO | ☑ | ☑ | |
| Hydro-Québec TransÉnergie (HQT) | ☑ | ☑ | For the existing system, HQT believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level. An approved Regional performance based methodology should be used to consistently determine this on a wide area basis. The same could apply for the Planning Authority/Coordinator for future equipment additions since the relay settings would be done during project development.<br>However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize the Drafting Team's critera. |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator.<br>For the purpose of this standard it is only necessary that the Planning Coordinators determine circuits critical to the reliability of the Bulk Electric System. While some Planning Coordinators may not yet have a documented process, the standard does require the responsible entity to have a documented process – this is not an option. | | | |
| Pacific Gas and Electric | ☑ | | The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO. |
| **Response:** In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator. | | | |
| Manitoba Hydro | ☑ | | However, the Reliability Coordinator should coordinate on the methodology to identify critical facilities with the Transmission Owners. |

| Question #1 | | | |
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| Commenter | Yes | No | Comment |
| | | | Also, this procedure to identify critical facilities should be coordinated with the procedure to identify critical assets in the Critical Infrastructure Protection Standards (CIP-002-1) to avoid potential confusion or conflict (i.e. two similar lists developed by different procedure). |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.<br>The drafting team modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in the two standards is not the same and would not be expected to result in the same list of facilities. | | | |
| MidAmerican | ☑ | | The standard does not appear to require the Reliability Coordinator to do this in conjuncton with the other Applicable Entities. R3.1.1 states This process shall include coordination with adjoining Reliability Coordinator(s). The MRO recommends that this requirement be expanded to include the other Applicable Entities listed in this standard.<br><br>The critical facilities list required by this standard, should be coordinated with the critical facilities lists required by other standards in as much as it it possible. |
| **Response:** Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.<br>The drafting team modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in the two standards is not the same and would not be expected to result in the same list of facilities. | | | |
| Pepco Holdings, Inc. Affiliates | ☑ | | |
| ITC Transmission | ☑ | | |
| National Grid | ☑ | | |
| Public Service Commission of South Carolina | ☑ | | |
| Consumers Energy Company | ☑ | | |

2. **The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement. Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.**

**Summary Consideration:** Many commenters indicated a lack of familiarity with 'mitigation time horizons' (now called simply 'time horizons'). These were introduced in NERC's ERO Application and again in NERC's Non-governance Compliance Filing as one of the elements used to determine the size of a sanction. (See Appendix 4 Paragraph 3.12 of the ERO Application, and Item 65 of the Non-governance Compliance Filing.)

Requirements that must be mitigated in real-time operations would have a larger sanction than those that could be mitigated over a longer time period. The comment form provided a list of possible mitigation time horizons. The latest version of the Reliability Standards Development Procedure did not include mitigation time horizons – this was an omission in bringing the manual into conformance with the latest ERO Rules of Procedure and this omission should be corrected with the next revision to the manual. In the meantime, stakeholders will be asked to comment on and approve mitigation time horizons as they are developed with standards. The alternative is to have these time horizons identified outside the standard development process, and stakeholders indicated they wanted a voice in the selection of all the compliance elements within standards. Note that the Standards Committee has since directed that the term, 'Time Horizon' be used rather than 'Mitigation Time Horizon' to more closely match the language used in the ERO Rules of Procedure.

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| Manitoba Hydro | | | Before we can comment on the appropriate assignment of Mitigation Time Horizons we need a better explanation of the concept of Mitigation Time Horizons and how Mitigation Time Horizons will be used to determine sanctions. MH appreciates the consideration of comments response on the Mitigation Time Horizon issue from the Balance Resources and Demand SDT. However their response does not sufficiently address our concerns. It would be helpful for stakeholder consideration of assignment of Mitigation Time Horizons, MH suggests, if NERC could post a clear proposed definition of the term Mitigation Time Horizon and provide a fuller explanation of intended use to determine the size of sanctions. We gather that the concept is that violations involving more immediate or real-time activities will generally incur larger panalties than violations involving |

| Question #2 | | | |
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| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | longer time frames. This is very vague. The suggested posting could serve as a draft addition to the Reliability Standards Development Procedure. Neither the comments in this form nor the ERO Rules of Procedure provide a definition or sufficient explanation. The term "Mitigation Time Horizon" does not appear in the Rules of Procedure or any other NERC document as far as we know. The term "Violation Time Horizon" on the Rules of Procedure is obviously related. |
| **Response:** Mitigation Time Horizons have been renamed, 'Time Horizons' to better match the terminology in the ERO Rules of Procedure. Please see the summary consideration of comments for a more detailed explanation of the specific locations where you can find more information on time horizons. | | | |
| PJM | | ☑ | Not sure what they mean in relation to a determination of non-compliance and the associated penaties. |
| **Response:** In accordance with the Sanctions Guidelines, the sanction associated with the violation of a real-time requirement should be larger than a violation of a requirement that is performed for the long-term planning horizon because there is more time to mitigate the violation that occurred for the long-term planning requirement. Please see the summary consideration of comments for a more detailed explanation of the specific locations where you can find more information on time horizons. | | | |
| MidAmerican | | ☑ | Mitigation Time Horizons are described near the top of this comment form.<br>The description of the Mitigation Time Horizons states The ERO Rules of Procedure include the use of mitigation time horizons as one element used to determine the size of sanctions.<br>Can the drafting team inform the Registered Ballot Body where the ERO definition of Mitigation Time Horizons can be found along with documentation describing how the mitigation time horizons will be used in determining penalties. Mitigation Time Horizons are not listed as a Performance Element of a Reliability Standard in the Reliability Standards Development Procedure Version 6 adopted by the NERC BOT on November 1, 2006. As such, it does not seem appropriate to include them in any Reliability Standards.<br><br>The comment form description of Mitigation Time Horizons further states The drafting team used the following guidelines in developing mitigation time horizons for each requirement, whereas the final statement in the description of the Violation Risk Factors states The |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | following categories of violation risk factors were approved with the latest version of the Reliability Standards Development Procedure. Like the Violation Risk Factors, the categories of Mitigation Time Horizons should also be approved and incorporated into the Reliability Standards Development Procedure in order to ensure that the definitions are consistent for all NERC Reliability Standards. The MRO cannot vote to approve a standard that includes Mitigation Time Horizons until the drafting team can produce ERO documented definitions and the documented manner in which the Mitigation Time Horizons will be used to determine penalties. |
| **Response:** Please see the summary consideration of comments. Modifications to the NERC Reliability Standards Development Procedure which occur over time affect existing standards as well as those under development. It is not practical to curtail all standards development activities until the NERC Reliability Standards Development Procedure reaches a final state. The drafting team needs to move this standard forward recognizing that future revisions may be necessary. | | | |
| Western Electricity Coordinating Council<br><br>Pacific Gas and Electric | | ☑ | While we agree that the horizons are probably adequate we have two areas of concern.<br><br>The first is the discrepancy between the 39 months in A.5.1.2 and the 24 months in B.R4.<br><br>Secondly we suggest that horizons be implemented to accommodate correction of issues of Security Level violations that may be found in the future. |
| **Response:**<br>The implementation plan includes a total of 39 months to allow the development of the initial list of circuits critical to reliability of the BES between 100-200 kV.<br><br>The 24 months is the time allowed to comply with R1 for facilities subsequently added to the initial list.<br><br>The last comment mixes time horizons and violation severity levels. While both elements are used in determining the size of a sanction, they represent different things – the time horizon identifies the time period associated with the requirement – since a requirement in real-time has very little time for mitigation that requirement should have a larger sanction than a requirement that, if violated could be mitigated over several years (like a long-term planning requirement) | | | |

| Question #2 | | | |
|---|---|---|---|
| Commenter | Agree | Do not agree | Comment |
| Violation Severity Levels identify how badly an entity 'missed' achieving a requirement. Complete failure is rated as severe and would lead to a higher sanction than a 'lower' rating where an entity was almost fully compliant. | | | |
| ITC Transmission | | ☑ | There is insufficient material describing the development and use of mitigation time horizons for inclusion in the Reliability Standards. It is premature to include them in these version of the Standards. When the Reliability Standards Development Procedure is updated to include a detailed description of their meaning and usage, only then should they be included in a Reliability Standard. |
| **Response:** Please see the summary consideration of comments. Modifications to the NERC Reliability Standards Development Procedure which occur over time affect existing standards as well as those under development. It is not practical to curtail all standards development activities until the NERC Reliability Standards Development Procedure reaches a final state. The drafting team needs to move this standard forward recognizing that future revisions may be necessary. | | | |
| Florida Reliability Coordinating Council | | ☑ | The "Mitigation Time Horizons" are not part of the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006. As such it is not clear why these were included in this standard.<br>We understand the description of "Mitigation Time Horizons" is provided in the comment form and the concept of "Violation Time Horizons" is included in the Sanctions Guidelines, appendix 4B (NERC Compliance Filing to FERC dated October 18th, 2006), but we feel these horizons are part of a broader policy issue and since their use is not clearly stipulated in the NERC standards process, including them in the standards will cause unnecessary confusion to stakeholders and regulators.<br>The mitigation (or violation) time horizons should be clearly stipulated in the Reliability Standards Development Procedure prior to their use in any standard (from a policy perspective). |
| **Response:** Please see the summary consideration of comments. Modifications to the NERC Reliability Standards Development Procedure which occur over time affect existing standards as well as those under development. It is not practical to curtail all standards development activities until the NERC Reliability Standards Development Procedure reaches a final state. The drafting team needs to move this standard forward recognizing that future revisions may be necessary.. | | | |
| Entergy Services, | ☑ | | |

| Question #2 | | | |
|---|---|---|---|
| Commenter | Agree | Do not agree | Comment |
| Inc. | | | |
| Pepco Holdings, Inc. Affiliates | ☑ | | |
| National Grid | ☑ | | |
| Progress Energy Carolina, Inc. | ☑ | | |
| Northeast Power Coordinating Council | ☑ | | |
| American Electric Power | ☑ | | |
| Public Service Commission of South Carolina | ☑ | | |
| Consumers Energy Company | ☑ | | |
| Hydro-Québec TransÉnergie (HQT) | ☑ | | |
| IESO | ☑ | | |

3. **The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.) Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.**

**Summary Consideration:** ***(Note that this question was asked by the Compliance Elements Drafting Team (CEDT) – and the CEDT provided the responses and made the conforming changes to the standard.)***
Based on stakeholder comments, the drafting team modified the Violation Severity Levels as follows:
Modified 2.4.1 to use the word, 'any' to clarify that the relay settings do not need to meet 'all' of he requirements in R1.1, just any one of the settings. The revised language states:

- Relay settings do not comply with **any of** the requirements in R1.1 through R1.13.

Added violation severity levels for failure to distribute the list of critical facilities within 30 days of the list's initiation or update. If the list was provided between 31 – 45 days this is a moderate violation; if the list was provided between 46 to 60 days, this is a High violation – and if the list was not provided or was provided after more than 60 days, this is now a 'Severe' violation.

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| Entergy Services, Inc. | | ☑ | The VRF for R1 is HIGH which we suggest should be MEDIUM. The specification of a particular criteria will not cause cascading outages. The use of a VRF of HIGH for relays should be applied to relays not set to the criteria. |
| **Response:** The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Note that the 'high risk requirement' includes potential to directly cause or contribute to a bulk electric system instability, separation, or cascading sequence of failure. Inadequate loadability was sited as a contibuting factor to the August 14, 2003 blackout. | | | |
| Alberta Electric System Operator - AESO | | ☑ | 1. Section D 2.2.1 "Evidence that the relay settings comply with criteria in R1.1 through 1.13 exists but is incomplete or incorrect for one or more of the requirements" - we recommend adding the |

| Question #3 | | | |
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| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | word "applicable" before the word "criteria" since the present wording could imply that compliance is required for all of the criteria.<br><br>2.Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13".<br>Firstly, "thought" should be changed to "through"; secondly, we think that it would be more appropriate to have different violation severity levels corresponding with the number of non-compliance to the sub-requirements (R1.1 to R1.13), instead of assigning the highest severity level for non-compliance with any one of the sub-requirements. |
| **Response:**<br>This is not a measure- after reviewing performance the compliance monitor looks at the violation severity levels to see which level best describes the performance. The word applicable was not added.<br><br>The typographical error was corrected.<br><br>Because an entity can choose 'any' of the criteria in R1.1 to R1.13, only one of these is applicable for any specific facility. | | | |
| Western Electricity Coordinating Council<br><br>Pacific Gas and Electric | | ☑ | We suggest the wordings for the specific sections in D.2. be changed to those shown below:<br><br>D.2.1.1 The applicable criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.<br><br>D.2.2.1 Evidence that relay settings comply with the applicable criteria in R1.1 through R1.13 exists, but is incomplete or incorrect for one or more of the requirements.<br><br>D. 2.4.1 Relay settings do not comply with any requirement R1.1 through R1.13 or evidence does not exist to support that relay |

| Question #3 | | | |
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| Commenter | Agree | Do not agree | Comment |
| | | | settings comply with any one of the criteria in R1.1 through R1.13. |
| **Response:** This is not a measure- after reviewing performance the compliance monitor looks at the violation severity levels to see which level best describes the performance. The word applicable was not added.<br><br>Because an entity can choose 'any' of the criteria in R1.1 to R1.13, only one of these is applicable for any specific facility.<br><br>The drafting team modified the violation severity level to adopt your suggestion | | | |
| National Grid | | ☑ | Section D, 2.4.1 states a Severe level violation applies when "Relay settings do not comply with R1.1 through R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13."<br><br>National Grid agrees that non-compliance of relay settings should constitute a Severe level violation. However, we believe that in cases where "Relay settings comply with one of the criteria in R1.1 through R1.13, but evidence does not exist to support that the relay settings comply" that a High level violation should apply. |
| **Response:** The proposal mixes two different requirements with a single violation severity level. Violation severity levels need to be assigned for each requirement and identify how badly the requirement was missed. If an entity has 'no evidence' it is at the 'severe' level, not at the 'high' level. | | | |
| Florida Reliability Coordinating Council | | ☑ | Although the violation severity levels (Lower, Moderate, High and Severe) are defined in the comment form provided and described as the basis for the DT's determinations, the levels are NOT defined in the current Reliability Standards Development Procedure. The term 'violation severity levels' is referenced generally in the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006 in the 'Compliance Elements of a Standard' section, as follows:<br>(Violation Severity Levels) - 'Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are balloted with the |

| Question #3 | | | |
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| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | standard, and developed by the NERC compliance program in coordination with the standard drafting team.'<br>Since the standards procedure does NOT include the definitions for Lower, Moderate, High and Severe, our main concern, again, is from a policy perspective. Although the definitions are included in the comment form, we feel this track will lead to confusion among stakeholders and regulators in this and other standard development activities. The process is requesting the industry to ballot and comment on a concept (Lower, Moderate, High and Severe) that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions.<br>The levels should be defined in the Reliability Standards Development Procedure prior to inclusion in balloting any standards. |
| **Response:** The comment form provided the definitions of Violation Severity Levels. The latest version of the Reliability Standards Development Procedure did not include the definitions of Violation Severity Levels – this was an omission in bringing the manual into conformance with the latest ERO Rules of Procedure and this omission should be corrected with the next normal revision to the manual. In the meantime, stakeholders will be asked to comment on and approve the Violation Severity Levels as they are developed with standards. The alternative is to have these Violation Severity Levels identified outside the standard development process, and stakeholders indicated they wanted a voice in the selection of all the compliance elements within standards. | | | |
| IESO<br>Northeast Power Coordinating Council<br>Hydro-Québec TransÉnergie (HQT) | | ☑ | (1) Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13. We find this confusing, and does not correspond to R1, which says:<br><br>"Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent …" We interpret this to mean that an entity is compliant if it meets at least one of the criteria listed in R1 through R1.13. |

| Question #3 | | | |
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| Commenter | Agree | Do not agree | Comment |
| | | | To add clarity to the text, we suggest rewording D 2.4.1 as follows:<br>"Relay settings do not comply with at least one of R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with at least one of the criteria in R1.1 through R1.13."<br><br>(2) Section D, 3.3.1 (Reliability Coordinator does not provide the list…) should be moved to the Severe level, 3.4.2 (Reliability Coordinator does not maintain a current list of facilities…) should be moved to the High level.<br><br>From our perspective there are 3 key elements in establishing the list of facilities critical to the reliability of the bulk electric system: 1) determining the facility list, 2) communicating the list to asset owners, and 3) maintaining the list.<br><br>The intent of R3 is to ensure that facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating the list of critical facilities is, in our view, one of the most important requirements. There is no such thing as a partial communication and so it's a case of either full compliant (communication) or flat out non-compliant (no communication at all). We therefore propose that 3.3.1 be moved to the Severe level.<br><br>If we accept the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does imply that the list has been communicated to the facility owners, and the requirement to maintain the list can be partially met. On the other hand, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 (Reliability Coordinator does not maintain a current list of facilities..) be moved to the High level. |

| Question #3 | | | |
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| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | Determining which facilities are critical to the reliability of the electric system is also an important first step. We agree that 3.4.1 should be retained at the Severe level, but propose to revise the sentence to read: "Reliability Coordinator does not have a process in place to determine, or evidence that it has determined, facilities that are critical to the reliability of the electric system." |
| **Response:**<br>The drafting team modified D2.4.1 to read as follows:<br>1. Relay settings do not comply with any of the requirements in R1.1 through R1.13<br>The drafting team considered your argument regarding the critical need for the Planning Coordinator to provide the list to the entities involved. Originally, the team did not want a severe violation to occur if the plan was distributed on day 31, which was why it was ranked high. The team has therefore decided to modify the severity levels so that there is a phase in of severity levels going from moderate to severe, depending on how delayed the entity was in distributing the list. The drafting team has modified Section D3 to read:<br>**3.2 Moderate:**<br>**3.2.1** Provided the list to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after list was established or updated.<br>**3.3 High:**<br>**3.3.1** Provided the list to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.<br>**3.4 Severe:**<br>**3.4.3** Did not provide the list to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after list was established or updated.<br>The drafting team believes that maintaining the list is as critical to reliability as creating the list in the first place. The team did not modify 3.4.2 | | | |
| MidAmerican | | ☑ | The MRO does not agree with the proposed Violation Severity Levels due to the fact that they have not been fully vetted in the |

| **Question #3** | | | |
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| **Commenter** | **Agree** | **Do not agree** | **Comment** |
| | | | Standards Development Process. A process which includes being held up for public comment, scrutiny and balloting. |
| **Response:** The violation severity levels were developed in accordance with the processes approved by the Compliance and Certification Committee and the Standards Committee. | | | |
| American Electric Power | | ☑ | We believe that the appropriate violation severity level designation for the violation described in Section D-2.2.1 should be "Lower" rather than "Moderate".<br><br>The language in D-2.2.1 and D-2.4.1 is ambiguous and should include references to the specific requirements that apply. |
| **Response:** The Drafting team feels that incomplete or incorrect application of settings is a moderate violation.<br><br>This is not a measure- after reviewing performance the compliance monitor looks at the violation severity levels to see which level best describes the performance. As per comments above, the word 'any' was added. | | | |
| Pepco Holdings, Inc. Affiliates | ☑ | | |
| ITC Transmission | ☑ | | |
| Progress Energy Carolina, Inc. | ☑ | | |
| Public Service Commission of South Carolina | ☑ | | |
| Consumers Energy Company | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PJM | ☑ | | |

4. **Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.**

**Summary Consideration:** No unnecessary adverse impacts on energy markets were identified.

| Question #4 | | | |
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| **Commenter** | **No Unnecessary Adverse Impacts** | **Unnecessary adverse impact on markets** | **Comment** |
| Entergy Services, Inc. | ☑ | | |
| Pepco Holdings, Inc. Affiliates | ☑ | | |
| Western Electricity Coordinating Council | ☑ | | |
| ITC Transmission | ☑ | | |
| National Grid | ☑ | | |
| Pacific Gas and Electric | ☑ | | |
| Progress Energy Carolina, Inc. | ☑ | | |
| Northeast Power Coordinating Council | ☑ | | |
| Public Service Commission of South Carolina | ☑ | | |
| Consumers Energy Company | ☑ | | |
| Manitoba Hydro | ☑ | | |
| Hydro-Québec TransÉnergie (HQT) | ☑ | | |
| IESO | ☑ | | |
| PJM | ☑ | | |
| MidAmerican | ☑ | | |

5. **The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?**

**Summary Consideration:** There was no consensus on whether a field test is needed. The commenters who indicated a field test is needed, had a variety of reasons for suggesting that a field test is needed. The drafting team will forward these comments to the Director, Compliance for use in determining whether to recommend a field test. Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.

| **Question #5** | | | |
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| **Commenter** | **No field testing is necessary** | **Field testing is necessary** | **Comments** |
| Sufana Engineering, Inc. | | ☑ | I would think that at least some of the lines should be tested to see if any of the NERC proposed requirements are actually able to be used. |
| **Response:** Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. Within those activities, every one of the sub-requirements within R1 were applied. | | | |
| Pacific Gas and Electric | | ☑ | Yes. field testing is recommended. Successful implementation depends on close communication between the Planning Authority, Transmission Operator and Reliability Coordinator. Requirements for documentation of compliance need to be clearly defined and understood by all parties. |
| **Response:** After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A field test of the coordination should not be needed as this is coordination that should already be taking place. | | | |

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| Florida Reliability Coordinating Council | | ☑ | This standard is extremely technical in nature as evidenced by the development of PRC-023 Reference document. The new concepts being addressed in the standard will also result in the involvement of new industry participants that have not been historically, involved in the NERC Reliability Standards process and the accompanying compliance concepts.<br>Based on the above, we recommend that a field test of the standard, to validate the measures and compliance elements, may highlight discrepancies and deficiencies in the measurability of the standard. We also feel that the field test may add additional insight and detail which could be added to the reference document or training material associated with the adoption of the standard. |
| **Response:** After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A field test of the coordination should not be needed as this is coordination that should already be taking place.<br><br>The drafting team cannot identify any new concepts or requirements that are assigned to industry participants that haven't historically been involved in the standards process or the 'beyond zone 3' relay review on which this standard is based.<br><br>Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. | | | |
| American Electric Power | | ☑ | While field testing may be difficult for PRC-023, it would be useful to provide a transition period wherein violations are reviewed, but not subject to sanction or fine. |
| **Response:** The purpose of a field test is to verify that the requirements, measures and compliance elements are correct and can be implemented as written. The purpose of a field test is not to provide entities with time to follow the standard without sanctions for non-compliance.<br>Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. | | | |

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| Public Service Commission of South Carolina | | ☑ | The PSCSC believes field testing is necessary, since NERC is significantly expanding the scope of facilities to which this standard will apply. |
| **Response:** Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. This standard does not expand the scope of applicable facilities beyond the requirements of the 'Beyond Zone 3' activities. | | | |
| Hydro-Québec TransÉnergie (HQT)<br>IESO<br>Northeast Power Coordinating Council | | ☑ | HQT believe the need for further field testing depends on the outcome of the final determination of what constitutes the BPS. Additional time or effort for field testing may be required to not only come into compliance if large additional portions of the lower voltage electric system are included, but to test the validity and coordination of the concepts contained in this standard. During NERC SPCTF's previous efforts pertaining to Beyond Zone 3 the application of the concepts were somewhat confined.<br>HQT believe the Standard as written should not be restricted to voltage classifications and should be applied to performance based BPS criteria elements. |
| **Response:** Final determination of what constitutes the 'BPS' is not relevant since the term 'BPS' is not used in the standard.<br><br>Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. This standard does not expand the scope of applicable facilities beyond the requirements of the 'Beyond Zone 3' activities.<br><br>After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A decision on what is critical at voltages lower than 200 kV is, under the revised standard, the decision of a Planning Coordinator - and is largely a local issue. A field test of the coordination should not be needed as this is coordination that should already be taking place. | | | |
| MidAmerican | | ☑ | The MRO believes that field testing is necessary so as to gauge if the time being allotted to the operators to respond is appropriate and to make sure the equipment is reasonably protected. |

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| **Response:** Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.<br>The drafting team is not aware of any real-time operating issues (associated with the implementation of the proposed requirements starting in 2003 with zone 3 NERC recommendation 8a requirements) that have been identified during the review and testing that has already taken place. | | | |
| Western Electricity Coordinating Council | ☑ | | While we don't necessarily believe that additional field testing is necessary for the proposed standards, standard 1.3.2 is different from the original exception 4 and will not have been tested. This also changes the requirements for series-compensated lines. |
| **Response:** The old 'technical exceptions' have been re-written as requirements. Although there have been some changes, these changes are not technically substantive. | | | |
| Entergy Services, Inc. | ☑ | | |
| Pepco Holdings, Inc. Affiliates | ☑ | | |
| Alberta Electric System Operator - AESO | ☑ | | |
| ITC Transmission | ☑ | | |
| National Grid | ☑ | | |
| Progress Energy Carolina, Inc. | ☑ | | |
| Consumers Energy Company | ☑ | | |
| Manitoba Hydro | ☑ | | |
| PJM | ☑ | | |

6. **If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.**

**Summary Consideration**: Based on stakeholder comments, the drafting team added the following to the list of exceptions in Attachment A of the standard:

- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings

The drafting team also made some minor clarifying changes as follows:

- Modified the applicability section to use the phrase, 'applied to the facilities defined in 4.1.1 through 4.1.4 ' rather than 'applied according 4.1.1 through 4.1.4.'
- Modified R1.10 to clarify that the transformer nameplate rating must be expressed in amperes
- Modified R1.10 to replace the word, 'applicable' with the following qualifying phrase:
  - Including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

The drafting team also made the following revisions to the effective dates in the implementation plan:

- For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
- For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.

| Question #6 | |
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| **Commenter** | **Comment** |
| Sufana Engineering, Inc. | This standard totally lacks fully worked out examples as to how to set the zone 3 relays. I would like to see complete detailed examples for each of the Relay Phase Settings sections. As the standard is presented now, it is essentially useless to the actual relay setter. Each example should have a complete ratings list of all of the equipment on the line (both summer and winter, short time, emergency, etc), the actual procedure of doing the relay setting (including comparing the apparent impedance versus the results based on loading), and final values for the sample lines. For each R1.xx, the first example should include a two terminal line. The second example for each R1.xx should include a three terminal line that has a very weak source. Each example should also show different relay shapes, i.e. mho, lens, trapezoidal, mho with a notched out section, trapezoidal with a notched out section, etc. There should also be fully worked out examples for current only based relays. |

| Question #6 | |
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| **Commenter** | **Comment** |
| | If the relay has the ability to notch out part of the characteristic around the line load angle, then questions as to how close to the angle should be addressed, i.e. if 30 degrees is the load angle, is plus/minus 5 degrees (thus the area from 25 to 35 degrees is notched out) OK? How close to the loadability point should the relay setting be should also be addressed. For all examples, a case that is deemed acceptable and one that is considered in violation should be presented.<br><br>I have had to set several 3 terminal lines that had a weak source that was actually an autotransformer tied to the line via a breaker. The resultant apparent impedance was so high that any setting would have been violation of the normal approach of using 1.15 times Irating. The result was that sequential tripping (which I consider to be not a good way to do things) was going to happen if the communications failed and that dual and perhaps triple layers of communication were needed. A fully worked out example of this type case should be included.<br><br>So the bottom line is that for each example, I would like to see the entire equipment rating list, the fault study results, and how the actual setting was determined. If it takes 20 pages to show the example, so be it. Examples that are only a two terminal lines will be considered by me to be insufficient. |
| **Response:** The standard establishes requirements but does not include procedures on 'how' to meet those requirements. Additional information is provided in the reference document which will be posted with the standard. The SDT observes that the Reference Document is a living document that can be updated as necessary. If worked examples are needed they can be added to the Reference Document by NERC. | |
| Entergy Services, Inc. | 1. The industry has determined that NERC reliability standards need to be more definitive as to which entities the standards are Applicable. Therefore, Entergy strongly suggests that all Applicability assignments in ALL standards and requirements be changed to be very specific. Recognizing the greater Applicability specified in this draft of the standard we think greater specificity is required. Therefore, we suggest the Applicability of each standard be changed to - ALL REGISTERED xxx, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD, where xxx is the functional entity to whom the standard applies. Therefore, the Applicability of PRC-023-1 should not be Transmission Owners but should be changed to - ALL REGISTERED TRANSMISSION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Reliability Coordinators should be changed to - ALL REGISTERED RELAIBILITY COORDINATORS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD;Generation Owners but should be changed to - ALL REGISTERED GENERATION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Distribution Providers but should be changed to - ALL |

| Question #6 | |
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| **Commenter** | **Comment** |
| | REGISTERED DISTRIBUTION PROVIDERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD.<br><br>The Applicability sections 4.1.2 and 4.1.4 should be changed from - AS DESIGNATED BY THE RELIABILITY COORDINATOR AS CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM - to - AS DESIGNATED BY THE RESULTS OF R3 OF THIS STANDARD.<br><br>2. In Applicability sections 4.2 and 4.3, please clarify the meaning, or applicability, of the term - applied according to 4.1.1 through 4.1.4. It is not clear what is meant by that phrase.<br><br>3. R3 contains the nebulous term - ARE CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM. This phrase is too vague and should be replaced by - ARE LIMITING FACILITIES DEFINED BY IROLs.<br><br>4. Measure M1 contains R1 and R4 in parentheses. We do not understand the meaning. Please re-write M1 so the relevance of R1 and R4 is clear. |
| **Response:**<br><br>1. The recommendation is for a format change, not a technical change. The existing language assigns the responsibility for identification to a functional entity and seems to be easier to understand. Under 'applicability' if there are no qualifying statements associated with a functional entity then the applicability is ALL – for example if there are no qualifying statements associated with the term, Transmission Owner, then the applicability is ALL Transmission Owners. The Energy Policy Act of 2005 requires that all entities that have activities within the electric power delivery area comply with mandatory reliability requirements.<br><br>2. The drafting team adopted your suggestion and modified the applicability section to use the phrase, 'applied to facilities defined in 4.1.1 through 4.1.4.'<br><br>3. The term, 'IROLs' was not adopted in the revised standard because this is not the only criteria that may be used when identifying facilities critical to the reliability of the Bulk Electric System.<br><br>4. The parentheses indicate that the measure applies to both R1 and R4. | |
| Pepco Holdings, Inc. Affiliates | PRC-023-1 Section F lists a reference document -PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings-. There is no statement in the actual standard as to whether the information and requirements contained within the reference document are part of the standard. The introductory sentence in the Reference Document states -This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.- It says it provides information and guidance, not requirements. Yet there are specific requirements contained within the reference document |

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| **Commenter** | **Comment** |
| | (such as Switch-on-to-Fault Setting Requirements). Either all requirements should be listed in the actual standard itself, or the standard should indicate there are additional requirements contained within the Reference Document.<br><br>In addition, Appendix D of the Reference Document states the following: -For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal.- The report is dated January 9, 2007, but the PRC-023-1 standard is not yet approved. The stated requirement mentioned above should not reference the date of formal adoption of the report, but the date of the formal adoption of the standard. |
| **Response:**<br><br>The reference document, while it may include the word, 'must', does not include any mandatory requirements.<br><br>The Appendix D of the Reference Document provides a discussion of how switch-on-to-fault schemes (SOTF) relate to relay loadability and provides guidance in how to consider SOTF in accordance with Attachment A, 1.3 of the Standard.<br><br>The drafting team modified the title of the reference document was modified to omit, 'PRC-023-1'. | |
| Alberta Electric System Operator - AESO | 1. Thermal Relays - Some direction should be provided regarding the use of themal emulation relays, either in the standard exclusions or in the reference document.<br><br>2. We have a concern about loading to 115% of the 15 minute rating for overhead lines. Specifically because ratings are often based on maximum allowable sag according to the National Electric Safety Code and intentionally loading above that level represents a safety code violation.<br><br>3. Determining and granting allowance for technical exceptions was previously done by the RRO. If this responsibility is assigned to the Reliability Coordinator there may not be consistency across the region.<br><br>4. R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. Four hour ratings are not presently used within Alberta.<br><br>5.R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 p.u. voltages. For |

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| | the bus voltage to dip to 0.85 p.u. the system impedance will have thavd to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in teh WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008. |
| **Response:**<br><br>1. The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings. Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions.<br><br>2. Exceeding any operating limit may result in an NESC violation. It is the responsibility of the operator, not the protective relay, to ensure that facilities are operated within their published limits.<br><br>3. The standard does not include any technical exceptions – compliance with all requirements is mandatory. The old 'technical exceptions' have been re-written as requirements.<br>Compliance monitoring is the responsibility of NERC as the ERO – and the ERO may delegate this responsibility to the Regional Entity.<br><br>4. The standard does not include a '4 hour Facility Rating' – the standard says, 'for the available defined loading duration nearest 4 hours'.<br><br>5. The old 'technical exceptions' have been re-written as requirements. Although there have been some changes, these changes are not technically substantive. | |
| Western Electricity Coordinating Council | 1. Some thermal emulation relays are used in SPS, but since they could operate independent of the SPS we wonder if there ought to be some discussion of them in the standard exclusions, or in the reference.<br><br>2. We suggest that, for clarity, "Facility" and "Facility Rating" definitions be copied from the "Glossary of Terms Used in Reliability Standards" to be included in either the standard or the reference.<br><br>3. We have concerns about loading to 115% of the 15 minute rating for overhead lines. Those ratings are often based on maximum allowable sag according to the National Electric Safety Code. Intentionally loading above that level may be in violation of the safety code. |

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| | 4. Previously the RRO had responsibility in determining allowance of technical exceptions, which provided consistency throughout the entire region. Moving those responsibilities to the Reliability Coordinators (RC) may change that consistency, thus treating entities differently depending on their RC.<br><br>5. R1 - There is no longer a loadability rating based on breaker rating (Exception 3).<br><br>6. R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. We have found that entities typically have continuous and short term, i. e., 15 minute, ratings defined, but not 4 hour ratings.<br><br>7. R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 per unit voltages. For the bus voltage to dip to 0.85 per unit the system impedance will have had to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in the WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008.<br>8. R1.4 - The current calculation for Exception 5 could have been based on Exception 2, 3, or 4 but was frequently based on 4. Since 4 has been significantly changed it will also change the allowed loadability of R1.4. We believe that this is another reason to keep R1.3.2 to be determined in the same manner as Exception 4. |
| **Response:**<br><br>1. The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings. Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions.<br><br>2. When a standard is approved, the new terms defined with that standard are transferred from the standard to the Glossary. The definitions do not remain with the standard once the standard is approved. Note that there are no new terms associated with the proposed standard.<br><br>**3.** The standard does not require any entity to have a 15-minute rating. Any 15-minute rating that is developed should be developed in a manner that allows the system operator to resolve the limit before any NESC violations occur. | |

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| 4. The standard does not include any technical exceptions – compliance with all requirements is mandatory. Compliance monitoring is the responsibility of NERC as the ERO – and the ERO may delegate this responsibility to the Regional Entity.<br><br>5. The breaker rating was used as a proxy for source impedance which was more restrictive than the actual source impedance. Therefore, R1.3.2 captures the essence of the requirement to have a loadability rating based on breaker rating.<br><br>6. The standard does not reference a '4 hour Facility Rating' because the time periods for which facility ratings are established vary from region-to-region. To address these differences the standard references, 'the available defined loading duration nearest 4 hours'. Exceeding any operating limit may result in an NESC violation. It is the responsibility of the operator, not the protective relay, to ensure that facilities are operated within their published limits.<br><br>7, 8. The old 'technical exceptions' have been re-written as requirements. Although there have been some changes, these changes are not technically substantive. | |
| ITC Transmission | Requirements R1.1 and R1.2 are written to allow transmission relays to be set as a percentage of "seasonal Facility Ratings" for a "defined loading duration." Not all transmission owners assign seasonal ratings to their transmission facilities (i.e., there is one rating for the full year).<br><br>Also, not all transmission owners have time-of-use ratings (e.g., 4-hour emergency ratings, 15-minute emergency ratings). Perhaps there is a way to clarify the requirements to ensure an entity with one rating is not in jeopardy of being found non-compliant sinply for not having a seasonal rating. ITC Transmission recommends a footnote to that effect, indicating that if seasonal ratings do not apply for a particular facility, then the full-year rating is to be used. Similarly, a footnote could also clarify that if a short-term or emergency rating has not been established for a particular facility, then the normal rating would apply (which, notably, would be more conservative than an emergency rating, since emergency ratings are generally higher than normal ratings). |
| **Response**: The standard does not require that an entity have multiple seasonal ratings. In regions that do not utilize multiple seasonal ratings, we expect that the one seasonal rating will be utilized in meeting R1.<br><br>The standard does not reference a '4 hour Facility Rating' because the time periods for which facility ratings are established vary from region-to-region. To address these differences the standard references, 'the available defined loading duration nearest 4 hours'. A footnote is not needed. | |
| National Grid | 1. The schedule for Switch-On-To-Fault (SOTF) protections applied on elements 200 kV and |

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| | above is the same as the Beyond Zone 3 schedule for the phase protections referenced in section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the Standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2.<br><br>2. In Section B, Requirement R1.10 additional specificity should be provided regarding the word applicable in the phrase "applicable maximum transformer nameplate rating.<br><br>3. In Section B, Requirement R1.11 additional specificity should be provided to clarify that the word supervision refers to blocking tripping of the transformer overload protection relays when the top oil or winding hot spot temperature is below the value specified in the Standard.<br><br>4. Investigation of protective relay misoperations sometimes identifies firmware problems that cause a relay to operate in an manner not intended by the manufacturuer. How would compliance be assessed in a case where a firmware problem is identified that prevents a relay from meeting the the relay loadability requirements? What process would exist for granting exemption from the Standard for such a problem that would affect all Entities that have applied the protective relay in question? |

**Response:**

1. The drafting team modified the implementation plan to support this suggestion – the revised effective dates are as follows:

- For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
- For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.

2. The drafting team modified R1.10 to eliminate the word, 'applicable' and added the following phrase: including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

3. The word, 'supervision' should be understood by protection engineers and the lack of comments on this requirement led the drafting team to believe that clarifying language is not needed.

4. While the entities are responsible for complying with the standard, the drafting team agrees that entities should be held to compliance only for those conditions under their control. While it is beyond the scope of the drafting team to address this issue, we hope that in the hypothetical case cited, while the entity would be in violation, the compliance monitor would be persuaded by the nature of the non-compliance, the identification of the problem, and the mitigation

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| plan (to perform the firmware upgrades or replace the relays as quickly as reasonably possible) to delay assessment of Sanctions. However, we do not know whether the compliance monitoring procedure would permit this course of action. | |
| Pacific Gas and Electric | (1)There are some technical differences between PRC-023 and NERC Recommendation 8a that need to be resolved. For example, NERC Recommendation 8a defined a term called the "Emergency Ampere Rating" of a transmission line, which includes an explanation of how this rating should be determined. NERC PRC-023 requires the use of a "Facility Rating" to determine the circuit loadability. The term "Facility Rating" should be similarly defined so as not to cause confusion later, especially if no field test is applied before implementation. Other specific comments on the technical differences between PRC-023 and NERC Recommendation 8a will be sent in by the WECC Relay Work Group.<br><br>(2) Need more clarification on SPS Schemes. Are all SPS schemes exempt or only the ones that meet NERC Reliability Criteria? Some SPS schemes are local in nature, do not affect neighboring utilities and failure of one of these schemes would not result in cascading events. These local SPS schemes may not be designed with the same degree of redundancy as SPS schemes that are in the WECC catalog and have been reviewed by the WECC RAS Reliability Subcommittee.<br><br>(3) Are line thermal overload schemes exempt? They are designed to take corrective action to prevent overloading a transmission line and by their nature may prevent loading the transmission line to levels required by R1.1 through R1.13.<br><br>(4) If a relay setting is found to not comply, is there an implementation period to comply?<br><br>(5) No sanctions have been associated with the different levels of non-compliance. When will these be defined? |
| **Response:**<br><br>1. Facility Rating is a defined term that encompasses the intent of the term, "Emergency Ampere Rating". Please see the response to WECC's comments.<br><br>2. This standard only exempts those SPS' that are subject to the NERC Reliability Standards PRC-012 through PRC-017.<br><br>**3.** The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings. Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions. | |

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| 4. Entities are responsible for complying with the requirements. The compliance monitoring section of the standard indicates that compliance may be assessed through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.<br><br>**5.** The sanctions guidelines are part of the ERO Rules of Procedure. | |
| Florida Reliability Coordinating Council | We have a concern with the associated "reference document", PRC-023 Reference. It is not clear how and where this document was developed. We understand that the document was created from previous references developed by the SPCTF. We would like to see a more formal vetting process of "reference documents". The cover sheet indicates it was prepared by the SPCTF of the NERC Planning Committee and that it is version 1.0, dated January 9, 2007. In review of meeting histories, we were not able to find the "formal" approval or adoption process of this document by the SPCTF or the PC.<br><br>We recommend that reference documents of this type should include a revision history along with approval history indicating what quality checks were performed on the document and which body (SPCTF, PC) sponsored its development and approved its publication.<br><br>If a reference document is created outside of the standards process it should contain an appropriate disclaimer stating so, to ensure that it is clear that Reliability standard in effect during compliance activities take precedence over references. This would be important, especially if synchronization or interpretation conflicts existed between the reference document and the Reliability standard. |
| **Response:**<br><br>The drafting team will submit the 'final' version of the reference document to the Standards Committee for approval to post the document with the approved standard. This is the process in the latest version of the Reliability Standards Development Procedure. If the Standards Committee directs the drafting team to get the approval of the Planning Committee, then the drafting team will do that.<br><br>At this point, the drafting team doesn't consider the reference document to be 'final'.<br><br>The drafting team will consider adding a version history to the final version of the document submitted for formal approval to the Standards Committee.<br><br>Standards are mandatory and enforceable and technical references are not. Restating this at the front of the technical reference does not seem necessary. | |

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| Northeast Power Coordinating Council | Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus. |
| **Response:** The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. | |
| American Electric Power | In response to question 4 above (there is no comment space provided), it is difficult to assess this impact on energy markets without having had the standard deployed. The referenced field test (or transition period) would be beneficial to make such a determination. |
| **Response:** Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'Beyond Zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. To date no market issues associated with the proposed requirements have been identified. | |
| Alabama Electric Cooperative, Inc. | 1. R4 should have provisions for temporary and technical exceptions on newly identified critical circuits. 2. The implementation dates in 5.1.2 and 5.2 needs to be clarified. For the initial list, the 39 month clock should start after the RC designates a circuit as critical. |
| **Response:** R4 does include 24 months for entities to comply with the requirements following the date of notification. Most stakeholders seemed to support the 24 months so it was not changed to 39. | |
| Consumers Energy Company | 1. Section 2.4.1, the word "thought" should be "through".<br><br>2. This standard is extremely difficult to understand and apply without the use of PRC-23 Reference Guide. This guide is very helpful in understanding what is being suggested and where the margins come from. However, it fails to give any guidance for criteria R1.13. Some examples or suggestions on how to use this criteria would be most helpful. Also, while the PRC-23 Reference Guide is listed as an "Associated Document" in Section F, it would seem helpful to mention this reference guide earlier in the standard (possibly as a note) as its use is important to correct application of these criteria. |
| **Response:** The typo in 2.4.1 was corrected.<br><br>R1.13 was intentionally put in the standard and left open-ended so entities would have an opportunity to identify and justify alternate ratings if needed based on conditions not covered by the other subrequirements of R1. It is anticipated this will be seldom utilized.<br><br>Because use of the reference is not mandatory, it is not referenced in the body of the requirements in the standard. | |
| Manitoba Hydro | A.3.<br>The word "Transmission loadability" need to be clearly defined/clarified. |

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| | Suggested wording:<br>1. Protective relay settings shall not limit transmission loadability which was determined by regional approved operating guidelines.<br>2. Protective relay settings shall not limit practical loading capability of a circuit<br><br>A. 4.2<br>Who is to ensure that the IPPs(generator owners) will comply with this standard?<br><br>B. R1.1.<br>"The highest seasonal Facility Rating of a circuit" is not clearly defined in this draft of the standard. It has been changed from the original term of "Emergency Ampere Rating" of a circuit Does this imply that the highest possible loading limit (which could be lower than the thermal rating) of a circuit can be used as the highest seasonal Facility Rating?<br><br>B. R1.10 and R1.11<br>How to distinguish transformer fault protection relays from overload protection relays<br><br>On R1.11, if overload protection is desired, can we add a phase overcurrent relay with a definite time delay of not less than 15 minutes, regardless of trip setting?<br><br>R1.11, the transformer overload relays must not trip at 150% of the maximum applicable nameplate rating. Does this mean the MVA rating of the transformer? Considering the need to evaluate loadability at 0.85 pu voltage, does this imply a requirement to set overcurrent relays at 165%?<br><br>B. R1.13<br>Manitoba Hydro appreciates the SDT adding this option which addresses our concern about being able to use stability limits as the maximum rating of a circuit.<br>We are curious to know, if we have a hard limit on the circuit, why is it nessesary to add another 15% on this limitation? For example, we have transformers which the manufacturer has subsequently advised us to restrict operation such that there is no loading above the continuous loading. In this case, being forced to add a margin would only subject the transformer to potential failure.<br>I believe that this could be written such that the aim would be to have a 15% margin unless there was evidence that equipment damage would occur. |

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| | B. In general Mantioba Hydro does not have major concerns with R2 but would like the SDT to consider two suggestions which we believe would add value to R2 specifically as it applies to R1.13.<br>Manitoba Hydro see the benefit in getting agreement between the Transmission Operator, the Planning Authority, and the Reliability Coordinator in developing limits. In some areas Mantioba Hydro would agree that this should be adequate. However areas that are close to a seam in any of these functions (TO, PA, or RC) should be seeking greater stakeholder approval.<br>Manitoba Hydro suggest that this could be accomplished by having the entitiy publish an operating guide for the facility in question. An operating guide would require the entity to seek further stakeholder input, and would still require, thorough other NERC standards, the approval of the appropriate functions under the NERC functional model.<br><br>The second concern is in the approval of ratings. In some jurisdictions, Mantioba is one, ratings which are different for the nameplate ratings would have to have the approval of a Professional Engineer with the right to practice within that jurisdiction. This is required because there is a safety issue regarding the operation of the equipment. This calls into question the legality of requiring various function under the NERC model to aprove (or agree with ratings) unless they have the legal right to set that rating.<br><br>Mantioba Hydro would suggest that name plate ratings should always be considered as appropriate limits. However when nameplate limits cannot be used for any reason, the entity owning the equipment will submit a notice, sealed by a Professional Engineer with the right to practice within the jurisdiction that the equipment resides, informing the TO, PA, and the RC why the nameplate ratings cannot be used and advising the variuos functions of the new ratings. The standard writing team should remember that a Professinal Engineer has a legal responsibility to stakeholders beyond the firm for which they practice, and that obligation should provide the independence sought for in this requirement. It also has the benefit of avoiding the potential situation where the TO, PA, and RC do not agree on a proposed rating.<br><br>C.<br>What would be considered as acceptable evidence?<br><br>Attachment A<br>2.<br>A word PERMANENTLY should be added before “block trip…”? |

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| | 3.3<br>I am not quite sure what exactly this mean? |

**Response:**

**A3 -** Most commenters seemed to accept the use of the term, 'transmisson loadability' without having this term formally defined.

**A4.2 -** Responsibility for ensuring compliance by IPPs is the same as for all other entities to whom this Standard is applicable.

**B. R1.1.** - 'Facility Rating' is a defined term. If an entity has only one seasonal rating for all seasons then that would be the highest seasonal Facility Rating of a circuit – similarly if an entity has 5 seasonal ratings, then comparing the 5 ratings and identifying the one that has the highest numerical value will result in the 'highest seasonal Facility Rating of that circuit.'

**B. R1.10 and R1.11 -** Typically, protective relays are designed to detect faults and not overload conditions. This standard addresses fault protecting relays.
Overload protection has a long response time as detailed in R1.11.
*(adding a phase overcurrent relay with a definite time delay of not less than 15 minutes, regardless of trip setting)* This would satisfy the standard as written, however an unusually low setting would be outside the spirit of the standard and would not represent a sound operating practice.

**R1.11 -** The drafting team replaced the word, 'applicable' with the following phrase:

- including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

The standard requires that relay loadability is evaluates at 0.85 pu voltage. The nameplate rating of a transformer is expressed in MVA based on 1.0 pu voltage which translates to an ampere rating on that same basis. The true thermal limit of the transformer is based on current, not MVA. For clarity, the drafting team modified the requirement to clarify that this is expressed in amperes.

**B. R1.13** - The 15% margin is for inherent error in the relay and sensing circuits. If overload protection is desired, please apply R1.11.

The entities listed in R2 already have responsibility for coordination.

There is no reliability-related reason to add the proposed new requirement.

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| The drafting team did modify R1.10 in response to other stakeholder comments and replaced the word, 'applicable' with the following phrase:<br>- Including the forced cooled ratings corresponding to all installed supplemental cooling equipment.<br><br>Each facility owner has the right to establish the rating of its facilities.<br><br>**C -** Any evidence (documentation or a demonstration) that shows that a specific relay meets any one of the criteria in R1 is acceptable. This could include a review of actual relay settings in the field, a review of a data base dump of relay settings and facility ratings, or a wide variety of other methods. The drafting team did not require any specific type of evidence to ensure that no entity would be required to invest resources solely for the purpose of demonstrating compliance.<br><br>**Attachment A 2-** Most commenters seemed to understand the intent of this item without futher clarification. If an out-of-step relay asserts on load and blocks the trip of fault protective relays, and a fault occurs during that loading condition, the out-of-step relay will prevent successful operation of the fault protective relay.<br><br>**3.3 -** This exempts schemes installed specifically to protect during stable power swings. Note that stable power swings occur, have been experienced, and are predictable in locations where load is substantially isolated from generation. | |
| Hydro-Québec TransÉnergie (HQT) | Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus. |
| **Response:** The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Question 6 allows entities to provide comments on any part of the standard, including VRFs. | |
| IESO | VRFs are now an integral part of the standards, which as a whole, require industry consensus for development and approval. Yet, there is no question asked on the concurrence on the violation risk factor levels for this draft, despite the fact that there are now new requirements assigned to the Reliability Coordinators. Is it an oversight, or is it an assumption that the assigned VRFs are acceptable to the industry?<br><br>In either case, we feel strongly that this question should be asked in order to provide the SDT an assessment of the acceptability of the assigned risk levels, although we do not disagree with any of the assigned risk levels. |

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| **Response:** The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Question 6 allows entities to provide comments on any part of the standard, including VRFs. | |
| PJM | In R1.5, weak-source systems needs to be defined.<br><br>In R1.6, remote to load needs to be defined. In R1.7 remote from generation stations and load center terminal needs to be defined.<br><br>in R1.8 and R1.9, remote to the system needs to be defined.<br><br>In R1.11, highest opertor established should be highest owner established. All instances of Reliability Coordinator in R3 and R4 should be changed to Planning Coordinator. |
| **Response:** The reference document provides additional discussion about the items listed and the drafting team will make a formal request to the Standards Committee to have the reference document posted with the approved standard. Most stakeholders accepted these terms without formal definitions.<br><br>The drafting team did replace the Reliability Coordinator with the Planning Coordinator in R3 and R4. | |
| MidAmerican | 1. Several companies in the MRO use line ratings of other than 4 hours. The MRO recommends the addition of a conversion factor for those companies using emergency ratings not consistent with what is stated in the standard. In lieu of a conversion factor, a standard line rating issued by NERC would be acceptable.<br><br>2. The MRO is concerned about what appears to be the forced assumption of risk with respect to overload levels and time durations that said overloads must be held. The MRO believes that it should be up to the Transmission Owner to determine the amount of risk they are willing to assume based on their own risk analysis.<br><br>3. In the Measures section under M3, the applicable entities listed for which the list of critical facilities must be provided to is not consistent with the applicable enities listed in R3 which M3 refers.<br><br>4. In the Violation Severity section, under violations for TOs, GOs, and DPs the definition of a Severe Violation is not complete.<br><br>5. The MRO is concerned that this standard is removing some inherent thermal overload |

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| | protection from the bulk electric system. In its response to comments the SAR drafting team stated - The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides, admittedly crude, overload protection and MRO believes there is increased inherent risk to the bulk electric system in the sentiment of the SAR drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? The MRO believes that a risk analysis should be conducted before implementing this standard.<br><br>6. The MRO believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with regard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive.<br>If during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wave traps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of service on time?<br><br>7. The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RROs are required to make this designation should be recommended by the SDT and added to the implementation plan.<br><br>8. Regarding the implementation plan, one would have expected an implementation time frame of the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven |

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| | months after establishment of the standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC is depending on all participants to have proceeded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did?<br><br>9. The MRO feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event.<br><br>10. The MRO has a concern with the 15 percent additional margin applied to the facility rating. This can be considered a negative margin with regard to protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy.<br><br>11. Does this standard expose the TO etc. to legal risk if there is damage to the public, violating vertical clearances for example?<br><br>12. If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems, (not to mention the human involvement, designed and maintained with equivalent reliability to the protection system? Also, the SCADA system may be down therefore the operator may not be able to assume the role of preventing equipment damage.<br><br>13. There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 p.u. voltage and power factor angle of 30 degrees criteria may not be appropriate for all cases.<br><br>14. This standard removes the option of using zone three relays to provide more reliable system operation<br>a. For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. Moving blinders in may make it impossible to detect fast moving swings. |

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| **Commenter** | **Comment** |
| | b. On interties: It may not be possible to set relays to detect the fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur.<br><br>15. This standard seems to be precluding the concept of TOs etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system.<br><br>16. In M1 and M2 it should be further clarified what is meant by evidence.<br>The draft standard states the "The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers." But for what scenario or number of contingencies is this statement accurate?<br><br>17. If a study is conducted to show that the 150% setting for zone 3 is not necessary, and the Transmission Owner wants to protect equipment with a more appropriate trip setting of say 125 percent, would the Transmission Owner have to prove that the setting is good for Category C for example; the Category C is listed in our question because the Transmission Owner typically is required only to plan for Category D only when the risk and consequences indicates there is a need to plan for such an event? The Transmission Owner can always come up with scenarios of contingencies that will trip a line or transformer, even at the 150 percent setting and not allow the operator time to react. Should the four hour rating be replaced with a one hour rating given that the four hour rating may be used to allow operator action rather than require relay or automatic control actions to remove a disturbance in a more timely fashion? |

**Response:**

1. The standard does not reference a '4 hour Facility Rating' because the time periods for which facility ratings are established vary from region-to-region. To address these differences the standard references, 'the available defined loading duration nearest 4 hours'.

2. There is no requirement to allow overloads to persist – the requirement is to prevent the relay from responding to overloads before the operators have time to take action. This standard does not preclude the operators from responding to overloads in time periods shorter than 15 minutes. It is the responsibility of the operator, not the protective relay, to ensure that facilities are operated within their published limits.

| Question #6 | |
|---|---|
| **Commenter** | **Comment** |
| 3. R3 and M3 require the list of critical facilities to be provided to TOs, GOs and DPs. The version of the standard that was posted was correct.<br><br>4. The version of the standard that was posted was complete. Please consult the NERC Reliability Standards Development Procedure for more information on definitions for Violation Severity Levels.<br><br>5. This standard balances loadability with response of protective relaying to heavy overloads. By improving the loadability of transmission facilities, the risk of cascading outages similar to the sequence of events that occurred on August 14, 2003 is mitigated significantly. The preliminary implementation of the proposed requirements and stakeholder comments both indicate that this standard is set at an acceptable level.<br><br>6. Most stakeholders indicated support of the standard as proposed. The drafting team developed the requirements so that they identify 'what' criteria must be met, and left the details of 'how' to achieve those requirements in the reference document. Facility ratings are based upon the most restrictive element. Facility Ratings provide the operator with the necessary information regarding ampacity and time duration limits to operate the system reliably.<br><br>7. The responsible entity has at least 21 months after the list is developed by the Planning Coordinator to become compliant. Most entities should already be mostly compliant with this standard through the 'Beyond Zone 3' activities.<br><br>8. Most commenters seemed to support the implementation plan as proposed. This standard was developed to codify some of the criteria that were identified as necessary to mitage relays from contributing to cascading blackouts. The activities to address this have been ongoing since early 2004 – and entities have stated that they are conforming to what have been 'NERC Board of Trustees directed activites'.<br><br>9. The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Note that the 'high risk requirement' includes potential to directly cause or contribute to a bulk electric system instability, spearation, or cascading sequence of failure. Inadequate loadability was sited as a contibuting factor to the August 14, 2003 blackout.<br><br>10. The 15% margin is for inherent error in the relay and sensing circuits.<br><br>11. This question is outside the scope of the drafting team.<br><br>12. There are other standards that require system operators to have facilities and systems in place and operational to operate the system within established system operating limits – and the system operating limits must be set to respect | |

| Question #6 | |
|---|---|
| **Commenter** | **Comment** |
| the associated facilty ratings.<br><br>13. These are the minimum criteria and prudent operation can always exceed them.<br><br>14. This concern appears to only be related to MHO relays and could be alleviated with the use of more modern relay technology.<br><br>15. Please see R 1.13.<br><br>16. Any evidence (documentation or a demonstration) that shows that a specific relay meets any one of the criteria in R1 is acceptable. This could include a review of actual relay settings in the field, a review of a data base dump of relay settings and facility ratings, or a wide variety of other methods. The drafting team did not require any specific type of evidence to ensure that no entity would be required to invest resources solely for the purpose of demonstrating compliance.<br><br>The standard is tied to the Facility Ratings independent of the operating condition.<br><br>17. See Requirement 1.12 for the 125% setting requirements and appropriately modify the facility ratings. | |

## Standard Development Roadmap

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**Development Steps Completed:**

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2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
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6. Drafting team posts second draft with implementation plan for comments (January 9–February 7, 2007).

**Description of Current Draft:**

This draft reflects conforming changes made to the standard based on comments submitted during the January 9–February 7, 2007 comment period. The drafting team has asked the Standards Committee for authorization to post the standard and implementation plan for a 30-day, pre-ballot review.

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| Anticipated Actions | Anticipated Date |
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## Definitions of Terms Used in Standard

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**None.**

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability.

**4. Applicability:**

**4.1.** Transmission Owners with phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the ~~Reliability~~ Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the ~~Reliability~~ Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.2.** Generator Owners with phase protection systems as described in Attachment A, applied ~~according~~ to facilities defined in 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4.

**4.4.** ~~Reliability~~ Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2, Requirement 4:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

**5.2.** Requirement 3: 18 months following applicable regulatory approvals.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature.

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning ~~Authority~~Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [~~Mitigation~~ Time Horizon: Long Term Planning]

**R3.** The ~~Reliability~~ Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its ~~Reliability~~ Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [~~Mitigation~~ Time Horizon: Long Term Planning]

**R3.1.** The ~~Reliability~~ Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall ~~include~~ consider input from ~~coordination with~~ adjoining Planning Coordinators and affected Reliability Coordinator~~(s)~~.

**R3.2.** The ~~Reliability~~ Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The ~~Reliability~~ Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its ~~Reliability~~ Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the ~~Reliability~~ Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [~~Mitigation~~ Time Horizon: Long Term Planning]

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1 and R4)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The ~~Reliability~~ Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The ~~Reliability~~ Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers.

## D. Compliance

**1.** Compliance Monitoring Process

### 1.1. Compliance Monitoring Responsibility

**1.1.1** ~~Electric Reliability Organization~~Regional Entity.

### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

### 1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The ~~Reliability~~ Planning Coordinator shall retain documentation of the most recent review process required in R3. The ~~Reliability~~ Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

### 1.4. Additional Compliance Information

The Transmission Owner, Generator Owner, ~~Reliability~~ Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels: Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 thought R1.13

**2.4.2** ~~or e~~Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3.** Violation Severity Levels: ~~Reliability~~ Planning Coordinator

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

~~3.2. N/A~~

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System ~~Reliability Coordinator does not provide the list~~ to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** ~~Reliability Coordinator d~~Does not have a process in place to determine facilities that are critical to the reliability of the Bulk ~~e~~Electric ~~s~~System.

**3.4.2** ~~Reliability Coordinator d~~Does not maintain a current list of facilities critical to ~~the~~ the reliability of the Bulk ~~e~~Electric ~~s~~System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## F. Associated Documents

1. ~~PRC-023 Reference —~~Determination and Application of Practical Relaying Loadability Ratings

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**~~3.7.~~3.8.** Relay elements associated with DC lines.

**~~3.8.~~3.9.** Relay elements associated with DC converter transformers.

## Standard Development Roadmap

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**None.**

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1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability.

4. **Applicability:**

   **4.1.** Transmission Owners with phase protection systems as described in Attachment A, applied to facilities defined below:

   **4.1.1** Transmission lines operated at 200 kV and above.

   **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

   **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

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   **4.3.** Distribution Providers with phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4.

   **4.4.** Planning Coordinators.

5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2, Requirement 4:

   **5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.

   **5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   **5.2.** Requirement 3: 18 months following applicable regulatory approvals.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per

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unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

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**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

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**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature.

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1 and R4)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers.

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Regional Entity.

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

**2. Violation Severity Levels: Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 thought R1.13

**2.4.2** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3.** Violation Severity Levels: Planning Coordinator

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

**3.4.2** Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## F. Associated Documents

**1.** Determination and Application of Practical Relaying Loadability Ratings

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**3.8.** Relay elements associated with DC lines.

**3.9.** Relay elements associated with DC converter transformers.

**Maureen E. Long**
Standards Process Manager

March 19, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

**Announcement: Comment Periods Open for SAR for Reliability Coordination, SAR for Operating Personnel Communications Protocols, and Relay Loadability Standard**

**The Standards Committee (SC) announces the following standards actions:**

**SAR to Modify the Reliability Coordinator Standards (March 19–April 17, 2007)**
The Reliability Coordination SAR drafting team posted the second draft of its SAR for Project 2006-06 for a 30-day comment period from March 19 through April 17, 2007.

The SAR proposes retiring, modifying or moving to other standards the Reliability Coordinator requirements contained within a set of ten already approved standards. The purpose of making these modifications is to ensure that the remaining requirements are clear, measurable, unique and enforceable; and to ensure that this set of requirements is sufficient to maintain reliability of the Bulk Electric System. This project also involves addressing concerns raised by FERC and stakeholders and involves bringing the set of standards into conformance with the ERO Rules of Procedure and the latest version of the Reliability Standards Development Procedure. Please use the comment form to provide comments on this SAR.

**SAR for Project 2007-02 Operating Personnel Communications Protocols (March 19–April 17, 2007)**
The Operating Personnel Communications Protocols SAR for Project 2007-02 is posted for a 30-day comment period from March 19 through April 17, 2007.

This SAR calls for the development of communications protocols for use by real-time system operators to improve situational awareness and shorten response time. The need for improved real-time communications protocols was identified during the investigation of the August 2003 Blackout. Please use the comment form to provide comments on this SAR.

**Transmission Relay Loadability Standard (March 19–April 17, 2007)**
The Transmission Relay Loadability drafting team posted the third draft of its standard for a 30-day comment period from March 19 through April 17, 2007. The drafting team is seeking comments on a change in the requirements that assigns responsibility for identifying certain critical facilities to the planning coordinator, in support of the latest approved version of the Functional Model.

The standard codifies the relay loadability criteria embodied in the NERC Recommendation 8a, *Improve System Protection to Slow or Limit the Spread of Future Cascading Outages*, and U.S.–Canada Power System Outage Task Force Recommendation 21A, *Make More Effective and*

*Wider Use of System Protection Measures.* Please use the comment form to provide comments on this standard.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply:
  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2, Requirement 4:
  - For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
  - For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.
- Requirement 3: Eighteen months following applicable regulatory approvals

### Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

### Modified Standards
There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

### Compliance with Standards
Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

### Proposed Effective Dates
Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

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- Requirement 3: Eighteen months following applicable regulatory approvals

Please use this form to submit comments on the draft PRC-023-1 standard. Comments must be submitted by April 17, 2007. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "Relay Loadability" in the subject line. If you have questions please contact Harry Tom at harry.tom@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☐ **MRO** | ☐ | 3 — Load-serving Entities |
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| ☐ **RFC** | ☐ | 5 — Electric Generators |
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| ☐ **SPP** | ☐ | 7 — Large Electricity End Users |
| ☐ **WECC** | ☐ | 8 — Small Electricity End Users |
| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background**

Following the last comment period, based on stakeholder comments and a review of the latest version of the Functional Model, the drafting team revised Requirement 3 to read as follows:

- The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

This change re-assigns responsibility for making the determination of the facilities critical to the reliability of the BES from the Reliability Coordinator to the Planning Coordinator. Because this task is performed in the 'long-term planning' time frame, this task should be assigned to the Planning Coordinator.

Compliance personnel recommended that the above requirement be field tested to verify that the Planning Coordinator is able to identify the facilities from 100 kV to 200 kV that are 'critical to the reliability of the Bulk Electric System'.

**The drafting team is seeking your input into these two changes. Please review the revised standard and answer the questions on the following page.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: Michael Calimano | | |
| Organization: New York Independent System Operator | | |
| Telephone: 518-356-6129 | | |
| E-mail: mcalimano@nyiso.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☒ | 2 — RTOs and ISOs |
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**Contact Telephone:**

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2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The NYISO believes that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200kV lines are built or relay loadability requirments are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class.

   A suggested change to address the issue we raise is to change the applicability to 100kV and above as determined by the Planning Coordinator.

Please use this form to submit comments on the draft PRC-023-1 standard. Comments must be submitted by April 17, 2007. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "Relay Loadability" in the subject line. If you have questions please contact Harry Tom at harry.tom@nerc.net or by telephone at 609-452-8060.

| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
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| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** Pepco Holdings, Inc. - Affiliates

**Lead Contact:** **Richard Kafka**

**Contact Organization:** **Pepco Holdings, Inc.**

**Contact Segment:** **1**

**Contact Telephone:** **301-469-5274**

**Contact E-mail:** **rjkafka@pepcoholdings.com**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Carl Kinsley | Delmarva Power and Light | **RFC** | 1 |
| Alvin Depew | Potomac Electric Power Co. | **RFC** | 1 |
| Evan Sage | Potomac Electric Power Co. | **RFC** | 1 |
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   ☒ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: While most Planning Coordinators have working relationships with Reliablity Coordinators, we are willing to accept the recommendation of Compliance personnel.

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

Please use this form to submit comments on the draft PRC-023-1 standard. Comments must be submitted by April 17, 2007. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "Relay Loadability" in the subject line. If you have questions please contact Harry Tom at harry.tom@nerc.net or by telephone at 609-452-8060.

| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Ed Davis | | |
| Organization: Entergy Services | | |
| Telephone: 504-576-3029 | | |
| E-mail: edavis@entergy.com | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Compliance personnel recommended that the above requirement be field tested to verify that the Planning Coordinator is able to identify the facilities from 100 kV to 200 kV that are 'critical to the reliability of the Bulk Electric System'.

**The drafting team is seeking your input into these two changes. Please review the revised standard and answer the questions on the following page.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

   We disagree with the use of the undefined phrase - CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM. We understand this phrase has been used in previous versions of this draft standard and this comment is late in the development. However, in the last several months the use of the term CRITICAL has taken new and much greater significance, and increased application to a wider range of the industry (for instance cyber security), that we suggest this undefined phrase be replaced with NERC defined terms.

   NERC has developed criteria to determine what facilities are critical to the relaibility of the bulk electric system. That criteria is defined in other NERC standards and results in IROLs. By definition of an IROL, if a facility is not related to an IROL then that facility is not critical to the reliability of the bulk electric system. Therefore, we suggest the undefined phrase - CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM - be replaced with - A FACILITY DEFINING AN IROL.

Please use this form to submit comments on the draft PRC-023-1 standard. Comments must be submitted by April 17, 2007. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "Relay Loadability" in the subject line. If you have questions please contact Harry Tom at harry.tom@nerc.net or by telephone at 609-452-8060.

| Individual Commenter Information<br>(Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: Dave Folk | | |
| Organization: FirstEnergy | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Dave Powell | ED Planning and Protection | | |
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   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

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| Individual Commenter Information (Complete this page for comments from one organization or individual.) | | |
|---|---|---|
| Name: | Roger Champagne | |
| Organization: | Hydro-Québec TransÉnergie (HQT) | |
| Telephone: | 514 289-2211, X 2766 | |
| E-mail: | champagne.roger.2@hydro.qc.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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   ☐ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: We believe that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence, in the applicability section (4.1) and Requirements R3, the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200kV lines are built or relay loadability requirements are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class and specifically applies to equipment 200kV and above.

   A suggested change to address the issue we raise is to change the applicability to 100kV and above as determined by the Planning Coordinator or just specify that it applies to equipment determined from an impact based methodology without specifying voltage.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Ron Falsetti | |
| Organization: | Independent Electricity System Operator - Ontario | |
| Telephone: | 905 855-6183 | |
| E-mail: | ron.falsetti@ieso.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| **Additional Member Name** | **Additional Member Organization** | **Region*** | **Segment*** |
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   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☒ Yes

   ☒ No

   Comments:
   The intent of R3 and its sub-requirements is to ensure that the Planning Coordinator determines the list of critical facilities in its area and to ensure facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating that list of critical facilities is, in our view, one of the most important aspects of these requirements.

   If one accepts the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does not imply that the list has been communicated to the facility owners. However, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 "Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System" be moved from "Severe" to the "High level".

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT**<br>☐ **FRCC**<br>☐ **MRO**<br>☐ **NPCC**<br>☐ **RFC**<br>☐ **SERC**<br>☐ **SPP**<br>☐ **WECC**<br>☐ **NA – Not Applicable** | ☐ | 1 — Transmission Owners |
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Group Comments (Complete this page if comments are from a group.)

**Group Name:** IRC Standards Review Committee

**Lead Contact:** **Charles Yeung**

**Contact Organization:** **SPP**

**Contact Segment:** **2**

**Contact Telephone:** **832-724-6142**

**Contact E-mail:** **cyeung@spp.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Mike Calimano | NYISO | **NPCC** | 2 |
| Alicia Daugherty | PJM | **RFC** | 2 |
| Ron Falsetti | IESO | **NPCC** | 2 |
| Matt Goldberg | ISO-NE | **NPCC** | 2 |
| Brent Kingsford | CAISO | **WECC** | 2 |
| Anita Lee | AESO | **WECC** | 2 |
| Steve Myers | ERCOT | **ERCOT** | 2 |
| William Phillips | MISO | **RFC+SERC+MRO** | 2 |
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   ☐ No

   Comments:

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   Comments:

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   If one accepts the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does not imply that the list has been communicated to the facility owners. However, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 "Does not maintain a current list of facilities critical to the reliability of the BES" be moved from "Ssever" to the "High level".

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Kathleen Goodman | |
| Organization: | ISO New England | |
| Telephone: | (413) 535-4111 | |
| E-mail: | kgoodman@iso-ne.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
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**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

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   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: We suggest either changing the applicability to be 100 kV and above as determined by the Planning Coordinator or BPS faciliites to be consistent with the recent FERC Order.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Brian F Thumm | |
| Organization: | ITC Transmission | |
| Telephone: | 248-374-7846 | |
| E-mail: | bthumm@itctransco.com | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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| ☐ **NA – Not Applicable** | ☐ | 9 — Federal, State, Provincial Regulatory or other Government Entities |
| | ☐ | 10 — Regional Reliability Organizations and Regional Entities |

Group Comments (Complete this page if comments are from a group.)

**Group Name:**

**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
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*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The Standard still emphasizes a distinct difference between 4-hour and 15-minute facility ratings, which suggests that each are required to be established. An explanatory note or footnote should clearly indicate that multiple facility ratings are not required to be established, and that a single rating can be used to satisfy both R1.1 and R1.2.

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| Individual Commenter Information (Complete this page for comments from one organization or individual.) | |
|---|---|
| Name: | Michael Gammon |
| Organization: | Kansas City Power & Light |
| Telephone: | 816-654-1242 |
| E-mail: | 816-654-1245 |

| NERC Region | | Registered Ballot Body Segment |
|---|---|---|
| ☐ ERCOT | ☒ | 1 — Transmission Owners |
| ☐ FRCC | ☐ | 2 — RTOs and ISOs |
| ☐ MRO | ☐ | 3 — Load-serving Entities |
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1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The Planning Coordinator in the NERC Functional Model is responsible for the coordination of generation and transmission plans of Transmission Planners, Resource Planners and other Planning Coordinators for the purpose of system analysis and subsequent coordination of plans or recommendations for modification to plans to meet system reliability planning critieria. They are responsible to provide results of the analysis to Reliability Coordinators. Ahead of time, Reliability Coordinators coordinate reliability related matters with Transmission Operators and Generator Operators to develop operating agreements or procedures regarding reliability related matters. The Reliability Coordinator coordinates operating procedures with other Reliability Coordinators and determines IROL limits. Fundamentally, the Planning Coordinator identifies areas of reliability concern and helps to plan asset additions or changes to address those concerns. The Reliability Cooridinator works with others to mitigate reliability concerns until such asset plans can be implemented and is responsible to establish SOL and IROL limits with Operators. The Reliability Coordinator is in the appropriate position to determine what facilities are critical to the operation of the region based on their responsibility to establish operating limits and operating agreements according to the NERC Functional Model.

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: If the Standard moves forward with the notion that the Planning Coordinator is responsible to identify critical facilities. A field test should reveal if the Planning Coordinator is the appropriate entity.

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: R2: Please review FAC-008-1, R3. Is the reuirement R2 in proposed standard PRC-023-1 the same as requirement R3 in FAC-008-1? I believe the intent of FAC-008-1 is for all entities to agree to the facility rating as determined by the asset owner. Agreement must be reached or R3 cannot be satisfied.

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| **Individual Commenter Information (Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | Robert Coish | |
| Organization: | Manitoba Hydro | |
| Telephone: | (204)487-5479 | |
| E-mail: | rgcoish@hydro.mb.ca | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☒ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
| ☒ **MRO** | ☒ | 3 — Load-serving Entities |
| ☐ **NPCC** | ☐ | 4 — Transmission-dependent Utilities |
| ☐ **RFC** | ☒ | 5 — Electric Generators |
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**Lead Contact:**

**Contact Organization:**

**Contact Segment:**

**Contact Telephone:**

**Contact E-mail:**

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   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☒ No

   Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: MH feels that some of our comments during the last two rounds of commenting periods have not been addressed. Mainly:

   1) Although the SDT repeatly stated that protection systems are designed to remove faults but not to prevent equipment damage, and the operator action is required to protect facilities from overload conditions, MH still believes that protection system can provide the last resort protection to prevent equipment damage especially during SCADA failure situations or situations when operators fail to correctly respond on overload conditions.

   2) Regarding R13, MH does not agree adding an 15% margin to the loading limitation on a circuit that has a hard loading limit. The SDT stated that this margin is for the inherent error in the relay and the sensing circuits. However, this error could be on the opposite side, such that the relay could trip only when the actual loading is higher than 100% of the hard loading limit in which case damage to the equipment could occur.

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| **Individual Commenter Information**<br>**(Complete this page for comments from one organization or individual.)** | | |
|---|---|---|
| Name: | | |
| Organization: | | |
| Telephone: | | |
| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
| ☐ **ERCOT** | ☐ | 1 — Transmission Owners |
| ☐ **FRCC** | ☐ | 2 — RTOs and ISOs |
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| Group Comments (Complete this page if comments are from a group.) | |
|---|---|
| **Group Name:** | Midwest Standards Collaboration Groiup |
| **Lead Contact:** | **Terry Bilke** |
| **Contact Organization:** | **Midwest ISO** |
| **Contact Segment:** | **2** |
| **Contact Telephone:** | **317-249-5463** |
| **Contact E-mail:** | **tbilke@midwestiso.org** |

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| David Lemmons | Xcel Energy | **MRO** | 6 |
| Jim Cyrulewski | JDRJC Associates | **RFC** | 8 |
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   ☒ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: To our knowledge, there are no entities registered as a Planning Coordinator. There is a need to differentiate the wide-area coordination that is done from the local transmission planner. The industry has not yet provided this differentiation in the standards.

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The standard relies on having a list of critical lines, transformers, and "facilities". The current standards use the term critical facilties in multiple standards. It is not clear if the facilities in this standard are the same as in the existing standards. If we don't know which facilities to which the standard applies, how can it be put in place?

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|---|---|---|
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| Organization: | | |
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| E-mail: | | |
| **NERC Region** | | **Registered Ballot Body Segment** |
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Group Comments (Complete this page if comments are from a group.)


**Group Name:** Midwest Reliability Organization

**Lead Contact:** **Joe Knight**

**Contact Organization:** **MRO for Group (Great River Energy for Lead)**

**Contact Segment:** **10**

**Contact Telephone:** **763.241.5633**

**Contact E-mail:** **jknight@grenergy.com**


| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Neal Balu | WPSR | **MRO** | 10 |
| Terry Bilke | MISO | **MRO** | 10 |
| Al Boesch | NPPD | **MRO** | 10 |
| Robert Coish, Chair | MHEB | **MRO** | 10 |
| Carol Gerou | MP | **MRO** | 10 |
| Ken Goldsmith | ALT | **MRO** | 10 |
| Todd Gosnell | OPPD | **MRO** | 10 |
| Jim Haigh | WAPA | **MRO** | 10 |
| Pam Oreschnik | XEL | **MRO** | 10 |
| Dick Pursley | GRE | **MRO** | 10 |
| Dave Rudolph | BEPC | **MRO** | 10 |
| Eric Ruskamp | LES | **MRO** | 10 |
| Mike Brytowski, Secretary | MRO | **MRO** | 10 |
| 27 Additional MRO Members | Not Named Above | **MRO** | 10 |
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1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

   ☒ Yes

   ☐ No

   Comments: In the SDT's Consideration of Comments from Draft 2, they indicated that the standard has already undergone extensive field testing in conjunction with NERC Recommendation 8a and the Beyond Zone 3 activities. What the SDT was not clear on was, if these activities were conducted with the RC as the responsible entity or the PC. If these activities have not been conducted with the PC as the responsible entity, the MRO recommends that additional field testing is needed. If however the PC was the responsible entity, the MRO does not believe any additional field testing is needed.

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

   ☐ Yes

   ☒ No

   Comments: The MRO does not believe that this standard in its current form is ready for ballot. The MRO believes that this standard is still too perscriptive and that there is a forced assumption of risk. The amount of risk that a company is willing to assume is a business decision that can only be determined from an in depth risk analysis.

   The MRO is interested to know if Facilities, as defined in this standard, that are determined by the PC to be critical to the reliability of the BES in its area are the same as Critical Facilities referenced in other Standards and, are these Critical Facilities covered under the heading of Critical Assets as defined in the NERC Glossary? Additionally, is the RC to maintain a separate list of Critical Facilities for each Standard or is there a master list of Critical Facilities that the RC is to maintain so as to avoid conflict? The MRO recommends that there be a consistient methodology throughout the standards as to what constitutes a Critical Facility. The MRO further recommends that Critical Facility be added to the list of defined terms in the Glossary.

   The VSLs do not appear to follow a smooth progression on the violation curve. For example; an Applicable Entity can violate between 1 and 13 of the subrequirements for

Requirement 1 and only be in a Moderate level violation. It would appear more appropriatre if there was a cut off that would constitute a High Level violation, such as violationg 75% or more of the subrequirements. The same reasoning can be applied to the VSLs for the PC. The PC can go from being compliant if it gets the list of the Critical Facilities to the Applicable Entities on or before to the due date, to having a Moderate level violation for being only one day late. The MRO recommends that the VSLs for the PC with respect to Critical Facility list submission to the Applicable Entities be separated such that if the PC is between 1 and 6 days late it be given a Lower level violation and once the PC is more than 7 days late it be given a Moderate level violation.

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Group Comments (Complete this page if comments are from a group.)

**Group Name:** NPCC CP9 Reliability Standards Working Group

**Lead Contact:** **Guy V. Zito**

**Contact Organization:** **Northeast Power Coordinating Council**

**Contact Segment:** **10**

**Contact Telephone:** **212-840-1070**

**Contact E-mail:** **gzito@npcc.org**

| Additional Member Name | Additional Member Organization | Region* | Segment* |
|---|---|---|---|
| Ralph Rufrano | New York Power Authority | **NPCC** | 1 |
| Ron Falsetti | The IESO, Ontario | **NPCC** | 2 |
| Roger Champagne | TransEnergie HydroQuebec | **NPCC** | 1 |
| Randy Macdonald | New Brunswick System Operator | **NPCC** | 2 |
| Herb Schrayshuen | National Grid US | **NPCC** | 1 |
| Al Adamson | New York State Reliability Council | **NPCC** | 10 |
| Kathleen Goodman | ISO-New England | **NPCC** | 2 |
| David Kiguel | Hydro One Networks | **NPCC** | 1 |
| William Shemley | ISO-New England | **NPCC** | 2 |
| Murale Gopinathan | Northeast Utilities | **NPCC** | 1 |
| Michael Schiavone | National Grid US | **NPCC** | 1 |
| Greg Campoli | New York ISO | **NPCC** | 2 |
| Donald Nelson | MA Dept. of Tele. and Energy | **NPCC** | 9 |
| Ed Thompson | ConEd | **NPCC** | 1 |
| Guy V. Zito | NPCC | **NPCC** | 10 |
| Michael Ranalli | National Grid US | **NPCC** | 1 |
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*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

**Background**

Following the last comment period, based on stakeholder comments and a review of the latest version of the Functional Model, the drafting team revised Requirement 3 to read as follows:

- The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

This change re-assigns responsibility for making the determination of the facilities critical to the reliability of the BES from the Reliability Coordinator to the Planning Coordinator. Because this task is performed in the 'long-term planning' time frame, this task should be assigned to the Planning Coordinator.

Compliance personnel recommended that the above requirement be field tested to verify that the Planning Coordinator is able to identify the facilities from 100 kV to 200 kV that are 'critical to the reliability of the Bulk Electric System'.

**The drafting team is seeking your input into these two changes. Please review the revised standard and answer the questions on the following page.**

*Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.*

1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

2. **Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments:

3. **Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

☐ Yes

☒ No

Comments: NPCC Participating members believe that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200kV lines are built or relay loadability requirments are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class.

A suggested change to address the issue we raise is to change the applicability to 100kV and above as determined by the Planning Coordinator.

The Relay Loadability standard drafting team thanks all commenters who submitted comments on Draft 3 of the Relay Loadability standard. This standard was posted for a 30-day public comment period from March 19 through April 17, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 14 sets of comments, including comments from 49 different people from 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The stakeholder comments submitted in response to the third draft of the Relay Loadability Standard did not indicate a need to make further modifications to the standard. Based on the drafting team's review of the comments received, the drafting team is recommending that this standard move to the balloting phase.

Note that following the closing of this comment period, the drafting team met and discussed observations of FERC staff, and made the following changes to the standard either in support of the FERC observations or to improve the clarity of the standard or to better support the compliance program:

- Revised the purpose statement to include stronger emphasis on the reliability objective behind this standard.
- Revised the proposed effective dates to align with the compliance program's request that all requirements become effective on the first day of a calendar quarter and to reflect that in some jurisdictions, the approval of a standard is tied to BOT adoption and not a separate regulatory approval.
- Inserted the phrase "load-responsive" into A4.1, A4.2 and A4.3 for clarification.
- Modified the second footnote for clarification.
- Added a third footnote to R1.11 to reference the IEEE standard that supports the requirement.
- Subdivided and relocated the text formerly in R4. to Section 5 Effective Dates and R1.
- Replaced the term Regional Entity with Compliance Enforcement Authority in Section D.
- Modified the Violation Severity Levels to include a reference to the associated requirement.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Relay-Loadability.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 1. | Anita Lee (G4) | AESO | | ✓ | | | | | | | | |
| 2. | Ken Goldsmith (G5) | ALT | | | | | | | | | | ✓ |
| 3. | Dave Rudolph (G5) | BEPC | | | | | | | | | | ✓ |
| 4. | Brent Kingsford (G4) | CAISO | | ✓ | | | | | | | | |
| 5. | Ed Thompson (G2) | ConEd | ✓ | | | | | | | | ✓ | |
| 6. | Karl Kinsley (G1) | Delmarva Power and Light | ✓ | | | | | | | | | |
| 7. | Ed Davis | Entergy Services, Inc. | ✓ | | | | | | | | | |
| 8. | Steve Myers (G4) | ERCOT | | ✓ | | | | | | | | |
| 9. | David Folk | FirstEnergy | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 10. | Dave Powell | FirstEnergy | ✓ | | | | | | | | | |
| 11. | Joe Knight (G5) | GRE | | | | | | | | | | ✓ |
| 12. | Dick Pursley (G5) | GRE | | | | | | | | | | ✓ |
| 13. | David Kiguel (G2) | Hydro One Networks | ✓ | | | | | | | | | |
| 14. | Roger Champagne (I) (G1) | Hydro-Québec TransÉnergie (HQT) | ✓ | | | | | | | | | |
| 15. | Ron Falsetti (I) (G2) (G4) | Independent Electricity System Operator | | ✓ | | | | | | | | |
| 16. | Kathleen Goodman (I) (G2) | ISO-NE | | ✓ | | | | | | | | |
| 17. | William Shemley (G2) | ISO-NE | | ✓ | | | | | | | | |
| 18. | Matt Goldberg (G4) | ISO-NE | | ✓ | | | | | | | | |
| 19. | Brian F. Thumm | ITC Transmission | ✓ | | | | | | | | | |
| 20. | Jim Cyrulewski (G3) | JDRJC Associates | | | | | | | | ✓ | | |
| 21. | Mike Gammon | Kansas City Power & Light | ✓ | | | | | | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 22. | Eric Ruskamp (G5) | LES | | | | | | | | | | ✓ |
| 23. | Donald Nelson (G2) | MA Dept. of Tele. and Energy | | | | | | | | | | ✓ |
| 24. | Robert Coish (I) (G5) | Manitoba Hydro | ✓ | | ✓ | | ✓ | ✓ | | | | |
| 25. | William Phillips (G4) | MISO | | ✓ | | | | | | | | |
| 26. | Terry Bilke (G3) (G5) | MISO | | ✓ | | | | | | | | |
| 27. | Carol Gerou (G5) | MP | | | | | | | | | | ✓ |
| 28. | Mike Brytowski (G5) | MRO | | | | | | | | | | ✓ |
| 29. | Randy MacDonald (G2) | NBSO | | ✓ | | | | | | | | |
| 30. | Herb Schrayshuen (G2) | NGRID | ✓ | | | | | | | | | |
| 31. | Michael Schiavone (G2) | NGRID | ✓ | | | | | | | | | |
| 32. | Michael Rinalli (G2) | NGRID | ✓ | | | | | | | | | |
| 33. | Murale Gopinathan (G2) | Northeast Utilities | ✓ | | | | | | | | | |
| 34. | Guy V. Zito | NPCC | | | | | | | | | | ✓ |
| 35. | Al Boesch (G5) | NPPD | | | | | | | | | | ✓ |
| 36. | Greg Campoli (G2) | NYISO | | ✓ | | | | | | | | |
| 37. | Mike Calimano (I) (G4) | NYISO | | ✓ | | | | | | | | |
| 38. | Ralph Rufrano | NYPA | ✓ | | | | | | | | | |
| 39. | Al Adamson (G2) | NYSRC | | | | | | | | | | ✓ |
| 40. | Todd Gosnell (G5) | OPPD | | | | | | | | | | ✓ |
| 41. | Richard J. Kafka (G1) | Pepco Holdings, Inc. – Affiliates | ✓ | | | | | | | | | |
| 42. | Alicia Daugherty (G4) | PJM | | ✓ | | | | | | | | |
| 43. | Alvin Depew (G1) | Potomac Electric Power Company | ✓ | | | | | | | | | |
| 44. | Evan Sage (G1) | Potomac Electric Power Company | ✓ | | | | | | | | | |
| 45. | Charles Yeung (G4) | SPP | | ✓ | | | | | | | | |
| 46. | Jim Haigh (G5) | WAPA | | | | | | | | | | ✓ |
| 47. | Neal Balu (G5) | WPSR | | | | | | | | | | ✓ |
| 48. | David Lemmons (G3) | Xcel Energy | | | | | | ✓ | | | | |

| Commenter | | Organization | Industry Segment | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| 49. | Pam Oreschnik (G5) | XEL | | | | | | | | | | ✓ |

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Pepco Holdings, Inc. – Affiliates
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Midwest Standards Collaboration Group
G4 – IRC Standards Review Committee
G5 – Midwest Reliability Organization (MRO)

## Index to Questions, Comments, and Responses

1. **The drafting team, in response to comments, has changed the responsible entity for R3 from Reliability Coordinator to Planning Coordinator. Do you agree with this change? If not, please explain in the comment area.**

**Summary Consideration:** Of the thirteen sets of comments received in response to this question, only one includes a "no" response. The response to that commenter is noted below.

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Kansas City P&L | | ☑ | The Planning Coordinator in the NERC Functional Model is responsible for the coordination of generation and transmission plans of Transmission Planners, Resource Planners and other Planning Coordinators for the purpose of system analysis and subsequent coordination of plans or recommendations for modification to plans to meet system reliability planning critieria. They are responsible to provide results of the analysis to Reliability Coordinators. Ahead of time, Reliability Coordinators coordinate reliability related matters with Transmission Operators and Generator Operators to develop operating agreements or procedures regarding reliability related matters. The Reliability Coordinator coordinates operating procedures with other Reliability Coordinators and determines IROL limits. Fundamentally, the Planning Coordinator identifies areas of reliability concern and helps to plan asset additions or changes to address those concerns. The Reliability Cooridinator works with others to mitigate reliability concerns until such asset plans can be implemented and is responsible to establish SOL and IROL limits with Operators. The Reliability Coordinator is in the appropriate position to determine what facilities are critical to the operation of the region based on their responsibility to establish operating limits and operating agreements according to the NERC Functional Model. |
| **Response:**<br><br>The Reliability Coordinator is primarily responsible for the real time and near-real-time operating horizons and R3 pertains to a planning horizon task. Therefore it seems appropriate for the Planning Coordinator to be assigned responsibility for complying with R3. These circuits may be identified by application of various operating-limit-definitions practices, such as determination of Interconnection Reliability Operating Limits (IROLs). | | | |
| Pepco Holdings, Inc. | ☑ | | |
| Hydro-Québec TransÉnergie | ☑ | | |

| Question #1 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| IESO | ☑ | | |
| NPCC CP9 RSWG | ☑ | | |
| Entergy | ☑ | | |
| FirstEnergy | ☑ | | |
| IRC Standards Review Committee | ☑ | | |
| ISO New England | ☑ | | |
| ITC Transmission | ☑ | | |
| Midwest SCG | ☑ | | |
| MRO | ☑ | | |
| NYISO | ☑ | | |

**2. Do you feel that a field test is necessary to confirm that the Planning Coordinator (as detailed in the NERC Functional Model and approved by the Board of Trustees on February 13, 2007) is able to perform the responsibilities detailed in R3 and R4? If not, please explain in the comment area.**

**Summary Consideration:** Of the 14 sets of comments, 6 showed that field testing is needed; 8 did not. There does not appear to be a consensus on this issue. The comments in response to this question have been referred to the NERC Compliance staff for their consideration in making a recommendation to the Standards Committee with respect to field testing.

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Pepco Holdings, Inc. | ☑ | | While most Planning Coordinators have working relationships with Reliablity Coordinators, we are willing to accept the recommendation of Compliance personnel. |
| **Response:** The drafting team acknowledges your comment. Thank you for submitting it. | | | |
| Kansas City P&L | ☑ | | If the Standard moves forward with the notion that the Planning Coordinator is responsible to identify critical facilities. A field test should reveal if the Planning Coordinator is the appropriate entity. |
| **Response:** The drafting team acknowledges your comment. Thank you for submitting it. | | | |
| Midwest SCG | ☑ | | To our knowledge, there are no entities registered as a Planning Coordinator. There is a need to differentiate the wide-area coordination that is done from the local transmission planner. The industry has not yet provided this differentiation in the standards. |
| **Response:**<br><br>In Version 3 of the Functional Model, the 'Planning Authority' was re-named the 'Planning Coordinator' and the Standards Committee directed drafting teams to begin using the term, 'Planning Coordinator' in standards, rather than the term, 'Planning Authority'. | | | |
| MRO | ☑ | | In the SDT's Consideration of Comments from Draft 2, they indicated that the standard has already undergone extensive field testing in conjunction with NERC Recommendation 8a and the Beyond Zone 3 activities. What the SDT was not clear on was, if these activities were conducted with the RC as the responsible entity or the PC. If these activities have not been conducted with the PC as the responsible entity, the MRO recommends that additional field testing is needed. If however the PC was the responsible entity, the MRO does not believe any additional field testing is needed. |
| **Response:** | | | |

| Question #2 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| The previous extensive field testing of the requirements did not consider application to the Planning Coordinator. Thank you for your input. | | | |
| Hydro-Québec TransÉnergie | ☑ | | |
| FirstEnergy | ☑ | | |
| IESO | | ☑ | |
| NPCC CP9 RSWG | | ☑ | |
| Entergy | | ☑ | |
| IRC Standards Review Committee | | ☑ | |
| ISO New England | | ☑ | |
| ITC Transmission | | ☑ | |
| Manitoba Hydro | | ☑ | |
| NYISO | | ☑ | |

**3. Other than the question posed in Questions 1 and 2, do you feel that this standard is ready to move forward to ballot? If not, please explain in the comment area.**

**Summary Consideration:** The voltage-level criterion was developed to produce a clear, specific applicability of this standard for circuits 200 kV and above, and to produce a consistent and measurable standard which can be monitored for compliance. Some entities may have circuits 200 kV and above which individually have little impact on the reliability of the bulk electric system. However, FERC, in its Order 693, showed considerable deference to the recommendations from the August 2003 blackout, and those recommendations were the basis of this standard's applicability to circuits 200 kV and above, and to "operationally-significant" lower voltage level circuits. The less-prescriptive criterion for applicability to lower-voltage-level circuits permits more flexibility in identifying these equally critical circuits. These circuits may be identified by application of various operating-limit-definitions practices, such as determination of Interconnection Reliability Operating Limits (IROLs).

All circuits, 200 kV and above, must be evaluated relative to any one of the sub-requirements of R1. Requirements R1.6, R1.7, R1.8, and R1.9 may support compliance with this Standard for such circuits that may not be individually critical to reliability of the BES.

Several commenters expressed disagreement with the assignment of violation severity levels but this disagreement was based on a misunderstanding that the violation severity levels assess 'importance' - violation severity levels are intended to measure the gap between the required and actual performance. Violation risk factors are used to assess the potential impact to reliability for the violation of a specific requirement.

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Hydro-Québec TransÉnergie | | ☑ | We believe that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence, in the applicability section (4.1) and Requirements R3, the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200 kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200 kV lines are built or relay loadability requirements are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200k V class and specifically applies to equipment 200kV and above.<br><br>A suggested change to address the issue we raise is to change the applicability to 100 kV and above as determined by the Planning Coordinator or just specify that it applies to |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | equipment determined from an impact based methodology without specifying voltage. |
| **Response:** See question #3 Summary Consideration above. | | | |
| NPCC CP9 RSWG | | ☑ | NPCC Participating members believe that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200kV lines are built or relay loadability requirments are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class.<br><br>A suggested change to address the issue we raise is to change the applicability to 100kV and above as determined by the Planning Coordinator. |
| **Response:** See question #3 Summary Consideration above. | | | |
| Entergy | | ☑ | We disagree with the use of the undefined phrase - CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM. We understand this phrase has been used in previous versions of this draft standard and this comment is late in the development. However, in the last several months the use of the term CRITICAL has taken new and much greater significance, and increased application to a wider range of the industry (for instance cyber security), that we suggest this undefined phrase be replaced with NERC defined terms.<br><br>NERC has developed criteria to determine what facilities are critical to the relaibility of the bulk electric system. That criteria is defined in other NERC standards and results in IROLs. By definition of an IROL, if a facility is not related to an IROL then that facility is not critical to the reliability of the bulk electric system. Therefore, we suggest the undefined phrase - CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM - be replaced with - A FACILITY DEFINING AN IROL. |
| **Response:** | | | |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| See question #3 Summary Consideration above. | | | |
| IESO | ☑ | ☑ | The intent of R3 and its sub-requirements is to ensure that the Planning Coordinator determines the list of critical facilities in its area and to ensure facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating that list of critical facilities is, in our view, one of the most important aspects of these requirements.<br><br>If one accepts the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does not imply that the list has been communicated to the facility owners. However, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 “Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System” be moved from “Severe” to the “High level”. |
| **Response:**<br><br>The drafting team agrees that communicating the list of critical facilities is one of the most important aspects of this standard, however the violation severity levels are not designed to measure ‘importance,’ they are designed to assess the degree to which an entity violated a specific requirement or sub-requirement. An entity that missed the entire intent of the requirement or sub-requirement (failure to maintain the list) has a ‘severe’ violation severity level. | | | |
| IRC Standards Review Committee | ☑ | ☑ | The intent of R3 and its sub-requirements is to ensure that the Planning Coordinator determines the list of critical facilities in its area and to ensure facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating that list of critical facilities is, in our view, one of the most important aspects of these requirements. There is no such thing as a partial communication and so it's a case of either full compliant (communication) or flat out non-compliant (no communication at all). We therefore propose that Severity level 3.3.1 be moved to the Severe level.<br><br>If one accepts the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does not imply that the list has been communicated to the facility owners. However, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 “Does not maintain a current list of facilities critical to the |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | reliability of the BES" be moved from "Ssever" to the "High level". |
| **Response:**<br><br>The drafting team agrees that communicating the list of critical facilities is one of the most important aspects of this standard, however the violation severity levels are not designed to measure 'importance,' they are designed to assess the degree to which an entity violated a specific requirement or sub-requirement. An entity that missed the entire intent of the requirement or sub-requirement (failure to maintain the list) has a 'severe' violation severity level. | | | |
| ISO New England | | ☑ | We suggest either changing the applicability to be 100 kV and above as determined by the Planning Coordinator or BPS faciliites to be consistent with the recent FERC Order. |
| **Response:**<br><br>See question #3 Summary Consideration above. | | | |
| ITC Transmission | | ☑ | The Standard still emphasizes a distinct difference between 4-hour and 15-minute facility ratings, which suggests that each are required to be established. An explanatory note or footnote should clearly indicate that multiple facility ratings are not required to be established, and that a single rating can be used to satisfy both R1.1 and R1.2. |
| **Response:**<br><br>It is only necessary to meet one requirement of R1.1 through R1.13 for each transmission line or transformer. The intent of the Standard is not to require that 4-hour and 15-minute ratings be established. Either the rating closest to a 4-hour rating is used in R1.1 or a 15-minute rating is used on R1.2. Requirement R1.2 is applicable only when a 15-minute rating has been published and is available to the Transmission Operator. | | | |
| Kansas City P&L | | ☑ | R2: Please review FAC-008-1, R3. Is the requirement R2 in proposed standard PRC-023-1 the same as requirement R3 in FAC-008-1? I believe the intent of FAC-008-1 is for all entities to agree to the facility rating as determined by the asset owner. Agreement must be reached or R3 cannot be satisfied. |
| **Response:**<br><br>FAC-008-1 R3 addresses overall review of a Facility Ratings Methodology, and PRC-023 (Draft) R2 addresses a group of specific ratings. The Drafting Team feels that these are not inconsistent, and that no changes are necessary. | | | |
| Manitoba Hydro | | ☑ | MH feels that some of our comments during the last two rounds of commenting periods |

| Question #3 | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | have not been addressed. Mainly:<br><br>1) Although the SDT repeatedly stated that protection systems are designed to remove faults but not to prevent equipment damage, and the operator action is required to protect facilities from overload conditions, MH still believes that protection system can provide the last resort protection to prevent equipment damage especially during SCADA failure situations or situations when operators fail to correctly respond on overload conditions.<br><br>2) Regarding R13, MH does not agree adding an 15% margin to the loading limitation on a circuit that has a hard loading limit. The SDT stated that this margin is for the inherent error in the relay and the sensing circuits. However, this error could be on the opposite side, such that the relay could trip only when the actual loading is higher than 100% of the hard loading limit in which case damage to the equipment could occur. |
| **Response:**<br><br>Your comments reflect a consistent position on this standard. We respect your position; however, within the industry there appears to be broad support for the position of the drafting team. | | | |
| Midwest SCG | | ☑ | The standard relies on having a list of critical lines, transformers, and "facilities". The current standards use the term critical facilties in multiple standards. It is not clear if the facilities in this standard are the same as in the existing standards. If we don't know which facilities to which the standard applies, how can it be put in place? |
| **Response:**<br><br>See question #3 Summary Consideration above. | | | |
| MRO | | ☑ | The MRO does not believe that this standard in its current form is ready for ballot. The MRO believes that this standard is still too perscriptive and that there is a forced assumption of risk. The amount of risk that a company is willing to assume is a business decision that can only be determined from an in depth risk analysis.<br><br>The MRO is interested to know if Facilities, as defined in this standard, that are determined by the PC to be critical to the reliability of the BES in its area are the same as Critical Facilities referenced in other Standards and, are these Critical Facilities covered under the heading of Critical Assets as defined in the NERC Glossary? |

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | Additionally, is the RC to maintain a separate list of Critical Facilities for each Standard or is there a master list of Critical Facilities that the RC is to maintain so as to avoid conflict? The MRO recommends that there be a consistient methodology throughout the standards as to what constitutes a Critical Facility. The MRO further recommends that Critical Facility be added to the list of defined terms in the Glossary.<br><br>The VSLs do not appear to follow a smooth progression on the violation curve. For example; an Applicable Entity can violate between 1 and 13 of the subrequirements for Requirement 1 and only be in a Moderate level violation. It would appear more appropriatre if there was a cut off that would constitute a High Level violation, such as violationg 75% or more of the subrequirements. The same reasoning can be applied to the VSLs for the PC. The PC can go from being compliant if it gets the list of the Critical Facilities to the Applicable Entities on or before to the due date, to having a Moderate level violation for being only one day late. The MRO recommends that the VSLs for the PC with respect to Critical Facility list submission to the Applicable Entities be separated such that if the PC is between 1 and 6 days late it be given a Lower level violation and once the PC is more than 7 days late it be given a Moderate level violation. |

**Response:**

First part - see question #3 Summary Consideration above.

Second part - It is only necessary to meet one requirement of R1.1 through R1.13 for each transmission line or transformer. It is not possible, on a given facility, to violate one, but not all of these - an entity will simply violate R1.

Third part - The compliance staff asserts that the Violation Severity Levels do follow a smooth progression. A lower violation means that while the responsible entity complied with the criteria laid out in the above sub-requirements, they did not obtain the agreement on the calculated capability from the Reliability Coordinator, Transmission Operator, and the Planning Coordinator.

A moderate violation is one that while the responsible entity attempted to use the criteria in the appropriate sub-requirement of R1.1-R1.13, it is either incomplete or incorrect. Please note that R1 is written such that the responsible entity is supposed to identify which method of relay setting is correct and to calculate the setting based on those criteria; not to comply with all of the sub-requirements.

A severe violation is when the relay settings do not comply with any of the requirements in R1.1 thought R1.13, or that no

| **Question #3** | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| evidence exists to show that the relay setting comply with those criteria. This means that the responsible entity did not calculate a relay setting based on any one of the sub-requirements, or they do not have the evidence to show that they have. Since it is not possible to prove compliance without evidence, both of these are rated as a severe violation.<br><br>With respect to the issue of lateness in providing a list of critical facilities. The compliance element drafting team felt that a lower severity level is inappropriate in this case as the entity is not 'mostly compliant' but is deficient with respect to one or more sub-requirements [minor detail]. The compliance element drafting team felt that providing a list of critical facilities is a significant element of this standard, and therefore falls appropriately under a moderate severity level. The proposed definition of a moderate severity level is "The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements."<br><br>The team felt that adding in an additional step from 46-60 days was appropriate before increasing the level of severity of the violation to "Severe", which is why the standard currently lists the failure to provide the list of critical facilities to the appropriate entities until 46-60 days after the list was made or updated, as a high severity level violation. | | | |
| NYISO | | ☑ | The NYISO believes that this standard should only apply to the BPS as determined by an approved FERC filed BPS region specific impact based methodology. Hence the standard should have references removed that specify voltage level and should only reference the BPS. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and on a going forward basis if further 200kV lines are built or relay loadability requirments are adjusted, the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class.<br><br>A suggested change to address the issue we raise is to change the applicability to 100kV and above as determined by the Planning Coordinator. |
| **Response:** See Question #3 Summary Consideration above. | | | |
| FirstEnergy | ☑ | | |
| Pepco Holdings, Inc. | ☑ | | |

## Standard Development Roadmap

*This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.*

**Development Steps Completed:**

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2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
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6. Drafting team posts second draft with implementation plan for comments (January 9–February 7, 2007).
7. Drafting team posts third draft for comments (March 19–April 17, 2007)

**Description of Current Draft:**

This drafting team did not make any technical changes to the standard based on comments received during the third posting. The compliance staff has not recommended field testing the compliance elements of this standard. The drafting team will ask the Standards Committee for authorization to post the standard and implementation plan for a 30-day, pre-ballot review.

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## Definitions of Terms Used in Standard

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**None.**

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability:**

**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2~~, Requirement 4~~:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

~~5.1.2 .~~

~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.~~

**5.2.** Requirement 3: First calendar quarter 18 months following applicable regulatory approvals; or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Relay settings for critical facilities added to the critical facility list pursuant to requirement R3.3 shall be set within 24 months of receipt of the notice from the Planning Coordinator. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

~~**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1~~) and R4 )~~

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

1. Compliance Monitoring Process

**1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority**

~~1.1.1Regional Entity.~~

**1.1.1** ~~Compliance Enforcement Authority~~Regional Entity for all responsible entities except those responsible entities that work for the Regional Entity

**1.1.2** ERO for all responsible entities that work for the Regional Entity

**1.2. ~~Compliance Monitoring Period and~~Violation Reset Time ~~Frame~~Period**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification ~~or~~, compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance ~~Monitor~~Enforcement Authority.

**2. Violation Severity Levels (R1, R2): Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 ~~thought~~through R1.13

**2.4.2** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels (R3): Planning Coordinator**

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

**3.4.2** Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## ~~F.Associated Documents~~

## F. Supplemental Technical Reference Document

~~The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies~~

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**3.8.** Relay elements associated with DC lines.

**3.9.** Relay elements associated with DC converter transformers.

## Standard Development Roadmap

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**None.**

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

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**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

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**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

**5.2.** Requirement 3: First calendar quarter 18 months following applicable regulatory approvals; or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Relay settings for critical facilities added to the critical facility list pursuant to requirement R3.3 shall be set within 24 months of receipt of the notice from the Planning Coordinator. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

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**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Enforcement Authority**

**1.1.1** Regional Entity for all responsible entities except those responsible entities that work for the Regional Entity

**1.1.2** ERO for all responsible entities that work for the Regional Entity

**1.2. Violation Reset Time Period**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels (R1, R2): Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 through R1.13

**2.4.2** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels (R3): Planning Coordinator**

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

**3.4.2** Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Maureen E. Long**
Standards Process Manager

October 18, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Initial Ballot Windows, Pre-ballot Review Period, and Ballot Pool Open

**The Standards Committee (SC) announces the following standards actions:**

### Initial Ballot Window for Urgent Action Revisions to BAL-004 is Open

The NERC Operating Committee has submitted an Urgent Action SAR to revise BAL-004-0 — Time Error Correction to remove the following from BAL-004:

- **Requirement 1, second sentence:** A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.
  - **Reason for removal:** The entities who have been serving as the Interconnection Time Monitors have done so voluntarily. The NERC Operating Committee is not a user, owner, or operator and has no authority to assign a reliability coordinator to serve as the Interconnection Time Monitor. The entities who have been serving as "volunteers" don't want to continue to serve in this role if they are subject to sanctions for non-compliance with Requirement 2, which supports a business practice.
- **Requirement 2:** The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.
  - **Reason for removal:** This requires the reliability coordinator to execute a time error correction in accordance with a NAESB business practice.

The initial ballot for the Urgent Action revisions to BAL-004 is open and will remain open until 8 p.m. on Monday, October 29, 2007.

### Initial Ballot Window for Interpretation of CIP-006-1 (for SCE&G) is Open

South Carolina Electric & Gas Company submitted a Request for an Interpretation of CIP-006-1 — Physical Security of Critical Cyber Assets. The request asked if dial-up remote terminal units (RTUs) that use non-routable protocols and have dial-up access are required to have six-wall perimeters or are only required to have electronic security perimeters.

The Interpretation clarifies that if dial-up assets are classified as critical cyber assets in accordance with CIP-002-1, the assets must reside within an electronic security perimeter; however, physical security control over a critical cyber asset is not required if that asset does not have a routable protocol. Entities are not required to enclose dial-up RTUs that do not use routable protocols within a six-wall border.

The initial ballot for the interpretation of CIP-006-1 is open and will remain open until 8 p.m. on Monday, October 29, 2007.

### Initial Ballot Window for Interpretation of BAL-005 Requirement R17 (for PGE) is Open

Portland General Electric Company submitted a Request for an Interpretation of BAL-005-1 Automatic Generation Control Requirement R17. The Interpretation asked if the requirement to annually check and calibrate time error and frequency devices applies to the following measuring devices:

- Only equipment within the operations control room
- Only equipment that provides values used to calculate automatic generation control area control error
- Only equipment that provides values to its SCADA system
- Only equipment owned or operated by the balancing authority
- Only to new or replacement equipment
- To all equipment that a balancing authority owns or operates

The Interpretation clarifies that Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the ACE equation or provide real-time time error or frequency information to the system operator. The time error and frequency measurement devices may not necessarily be located in the operations control room or owned by the balancing authority; however, the balancing authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in Requirement 17.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

The initial ballot for this interpretation of BAL-005 Requirement 17 is open and will remain open until 8 p.m. on Monday, October 29, 2007.

### Pre-ballot Window and Ballot Pool for PRC-023-1 — Relay Loadability Opens October 18, 2007

A new standard, PRC-023-1 — Relay Loadability, is posted for a 30-day pre-ballot review through 8 a.m. on November 19, 2007.

This standard was developed to address the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called 'zone 3 relay' issue that has been expanded to address other protection devices subject to unintended operation during extreme system conditions. The proposed standard establishes minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

The ballot for this standard will also include the Relay Loadability Implementation Plan.

The ballot pool to vote on this standard was formed earlier this year and has been re-opened. Anyone who joined the ballot pool earlier this year and is still a valid member of the Registered Ballot Body will not need to re-join the ballot pool. The ballot pool will remain open until 8 a.m. Monday, November 19, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is:

bp-Relay Loadability_in@nerc.com

## Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply:
  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2:
  - For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.
  - For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals or, , in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.
- Requirement 3: At the beginning the first calendar quarter 18 months after applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

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There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

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  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2~~, Requirement 4~~:
  - For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.
  - For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter ~~42~~ 39 months after applicable regulatory approvals or, , in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.
- Requirement 3: At the beginning the first calendar quarter 18 months after applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

# PRC-023 Reference

# Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Corporation

Prepared by the

System Protection and Control Task Force

of the

NERC Planning Committee

***Version 1.0***

***January 9, 2007***



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# Table of Contents

# Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Protection systems intended for protection during stable power swings
   - 2.4. Generator protection relays that are susceptible to load
   - 2.5. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017. Protection systems that are

designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

2.6. Relay elements associated with DC lines

2.7. Relay elements associated with DC converter transformers

# Requirements Reference Material

## R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

## R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{rating}$ = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating ($I_{rating}$) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

## R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been

determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating ($I_{rating}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

## R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

### R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

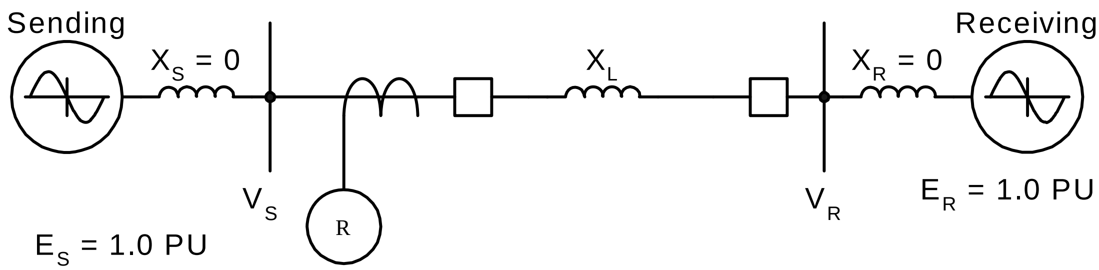



**Figure 1 – Maximum Power Transfer**

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin \delta}{X_L}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$\delta$ = Voltage angle between $Vs$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$I_{real}$ = Real component of current

$V$ = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

$I_{total}$ is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$ (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

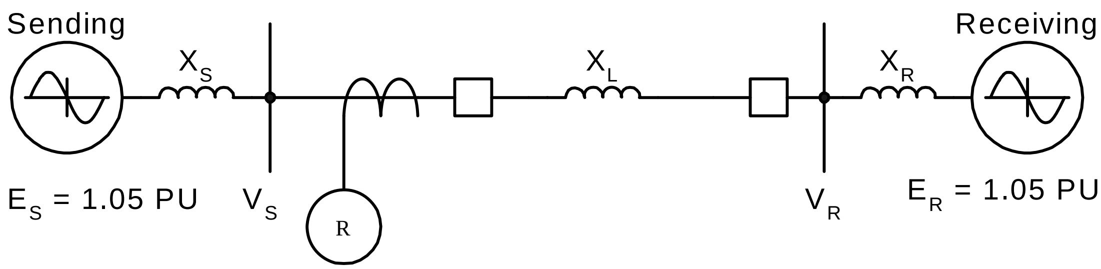



**Figure 2 – Site-Specific Maximum Power Transfer Limit**

The recommended procedure for determining $X_S$ and $X_R$ is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude ($I_{real}$) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

$V$ = Nominal phase-to-phase system voltage

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{\left(X_S + X_R + X_L\right)}}$$

Where:

$I_{total}$ = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

## R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess

of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

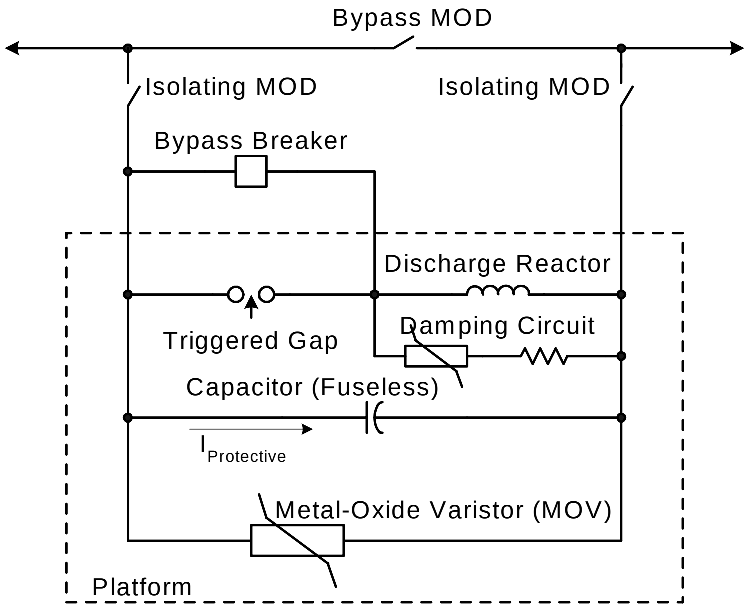



**Figure 3 – Series Capacitor Components**

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

$X_C$ = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because $I_{total}$, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. $I_{total}$ (where $I_{total}$ is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

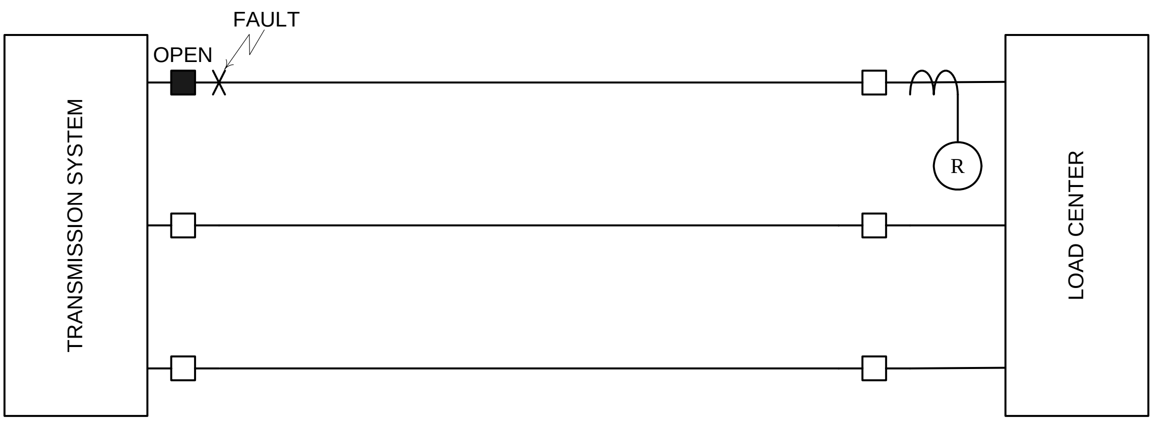



**Figure 4 – Weak Source Systems**

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{{V_S}^2 + {V_R}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$I_{max} = 1.15 \times \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{max} = 1.71 \times I_{fault}$$

Where:

$I_{fault}$ is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times $I_{fault}$, where $I_{fault}$ is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

## R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current ($I_{max}$) that the line will experience.

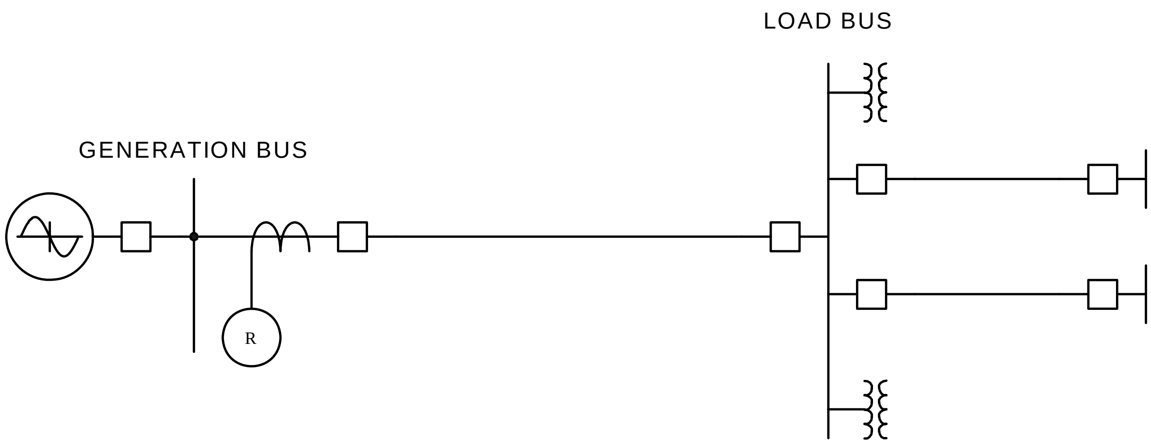



**Figure 5 – Generation Remote to Load Center**

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amperes at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$\boxed{I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}}$$

Where:

$V_{relay}$ = Phase-to-phase voltage at the relay location

$N$ = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the $I_{max}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

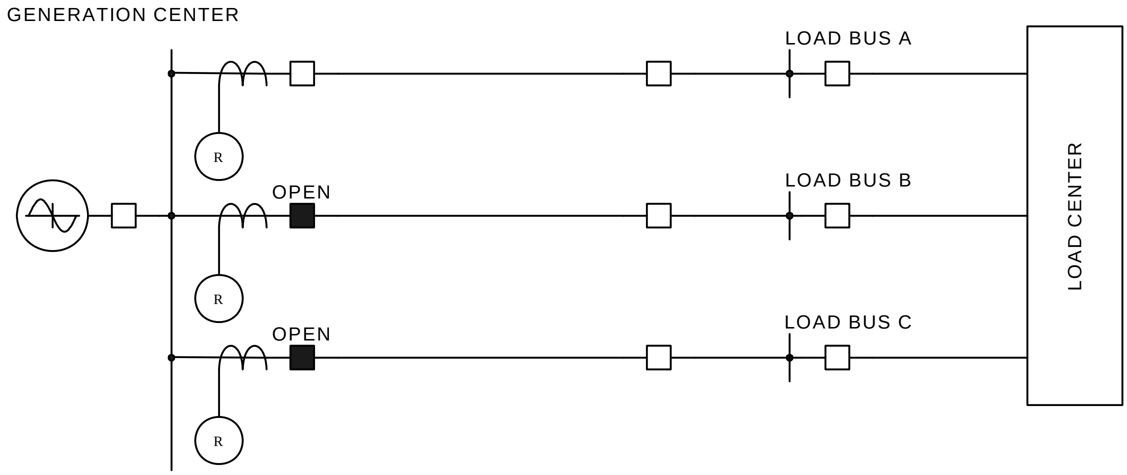



**Figure 6 – Generation Connected to System – Multiple Lines**

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The $I_{max}$ expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds $I_{max}$.

Set the tripping relay so it does not operate at or below 1.15 times $I_{max}$, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

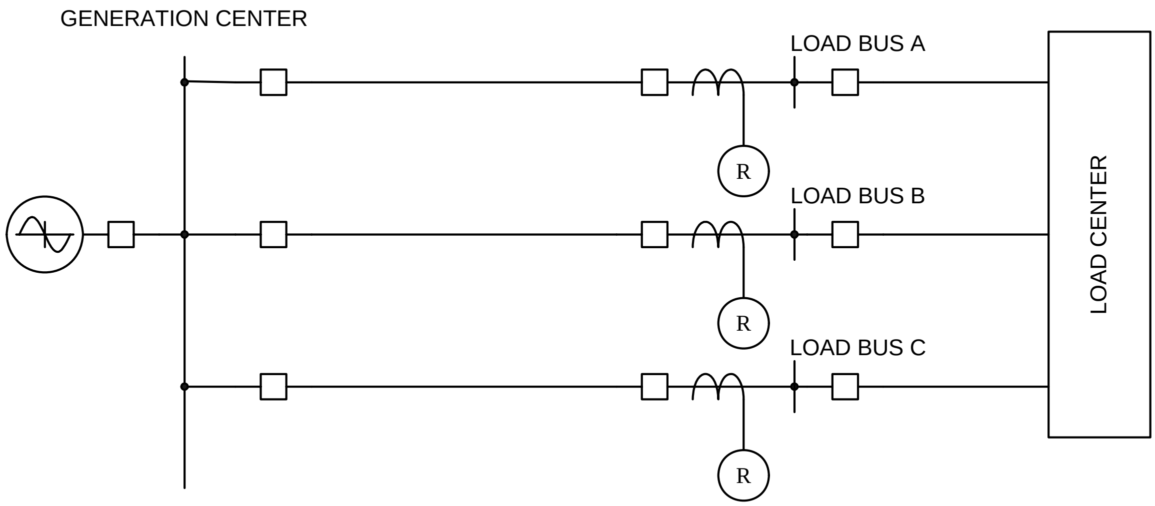



**Figure 7 – Load Remote to Generation**

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow ($I_{max}$) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

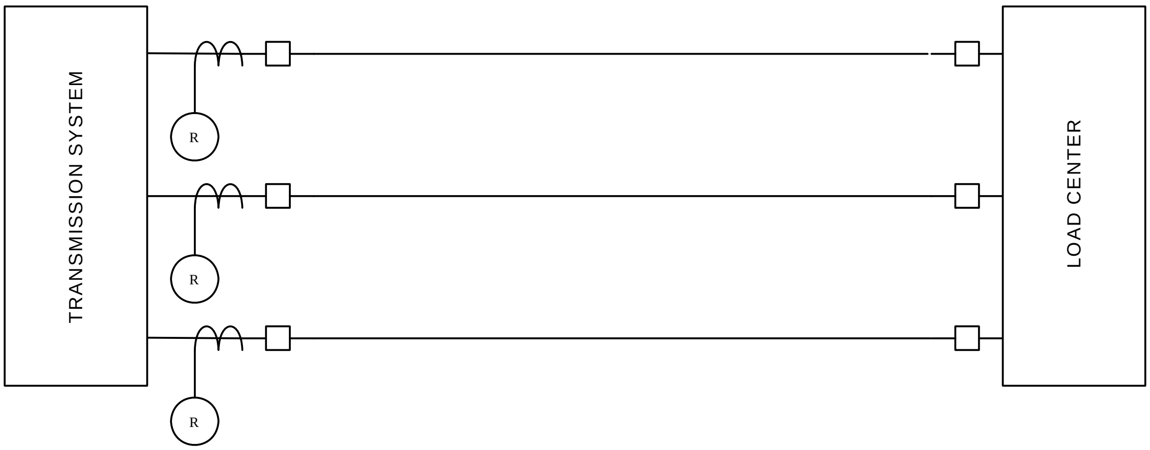



**Figure 8 – Remote Cohesive Load Center**

Also, one must determine the maximum power flow on an individual line to the area ($I_{max}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.

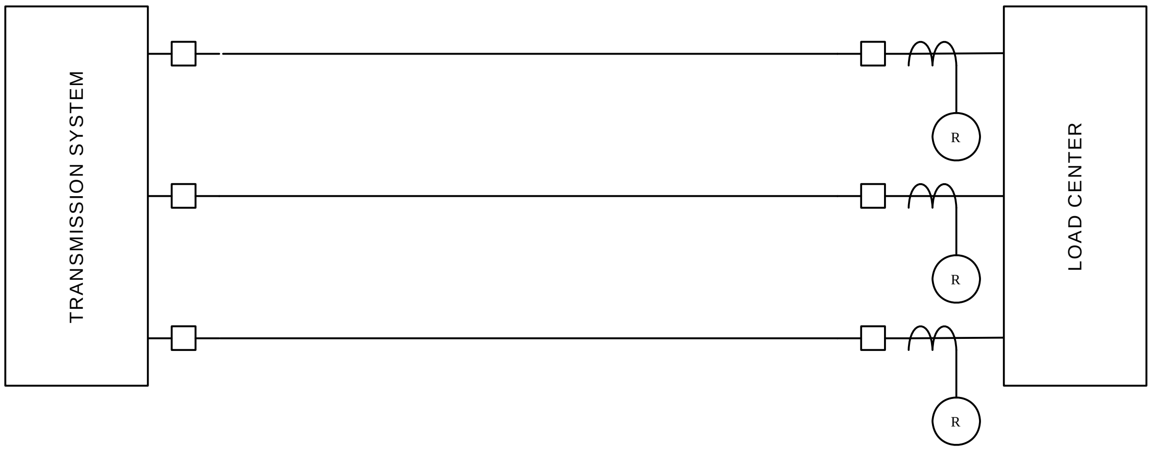



**Figure 9 – Cohesive Load Center Remote to Transmission System**

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow ($I_{max}$)from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

## R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer, and addresses protection that is intended to protect the transformer from thermal overloads.

1. Set the overload protection relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator-established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload, or
2. Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting shall be no less than 100° C for the top oil or 140° C[5] for the winding hot spot temperature.

## R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not "overly sensitive," and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

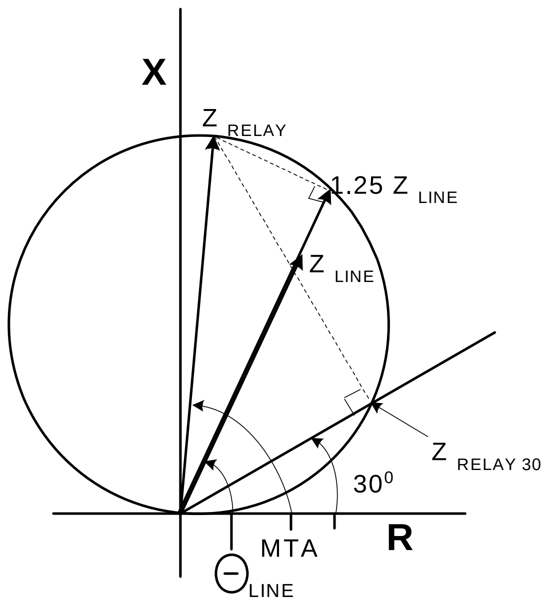



**Figure 10 – Long Line relay Loadability**

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

- $V_{relay}$ = Phase-to-phase line voltage at the relay location
- $Z_{line}$ = Line impedance
- $\Theta_{line}$ = Line impedance angle
- $Z_{relay}$ = Relay setting at the maximum torque angle
- $MTA$ = Maximum torque angle, the angle of maximum relay reach
- $Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current
- $I_{trip}$ = Trip current at 30 degrees with normal voltage
- $I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{line})}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

## R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

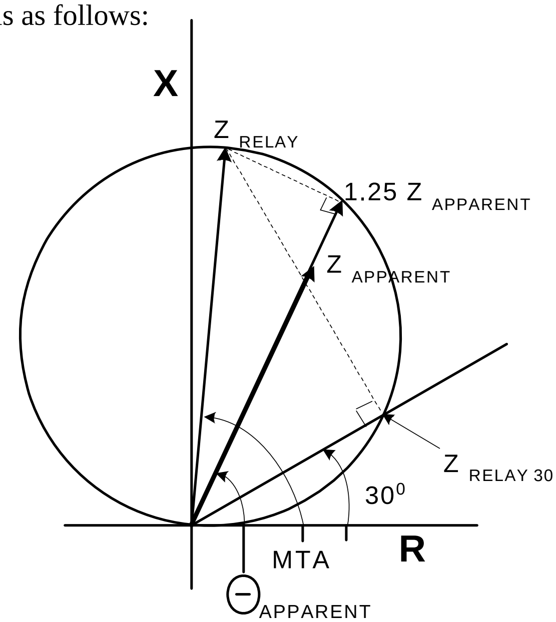



**Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps**

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

$Z_{relay}$ = Relay setting at the maximum torque angle.

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

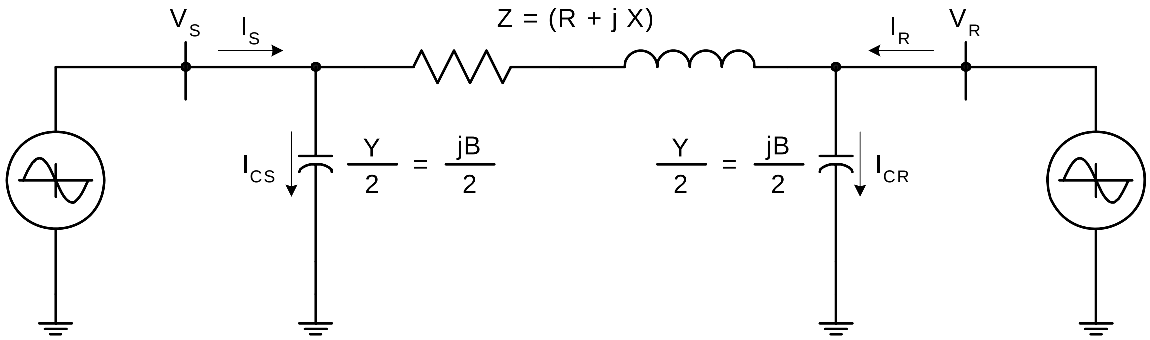
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

# Appendices

# Appendix A — Long Line Maximum Power Transfer Equations




Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\cos(\theta^\circ) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta^\circ)$$

$$Q_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\sin(\theta^\circ) - V_S^{\ 2}\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta^\circ)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos(\theta^\circ) + \sin(\theta^\circ)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta^\circ) - |Z|\frac{B}{2} - \cos(\theta^\circ)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{I_{real}^{\ 2} + I_{reactive}^{\ 2}}}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$V$ = Nominal phase-to-phase bus voltage

$\delta$ = Voltage angle between $V_S$ and $V_R$

$Z$ = Reactance, including fixed shunt reactors, of the transmission line in ohms*

$\Theta$ = Line impedance angle

$B$ = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

# Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

### *Unmodified Permissive Overreaching Transfer Trip*

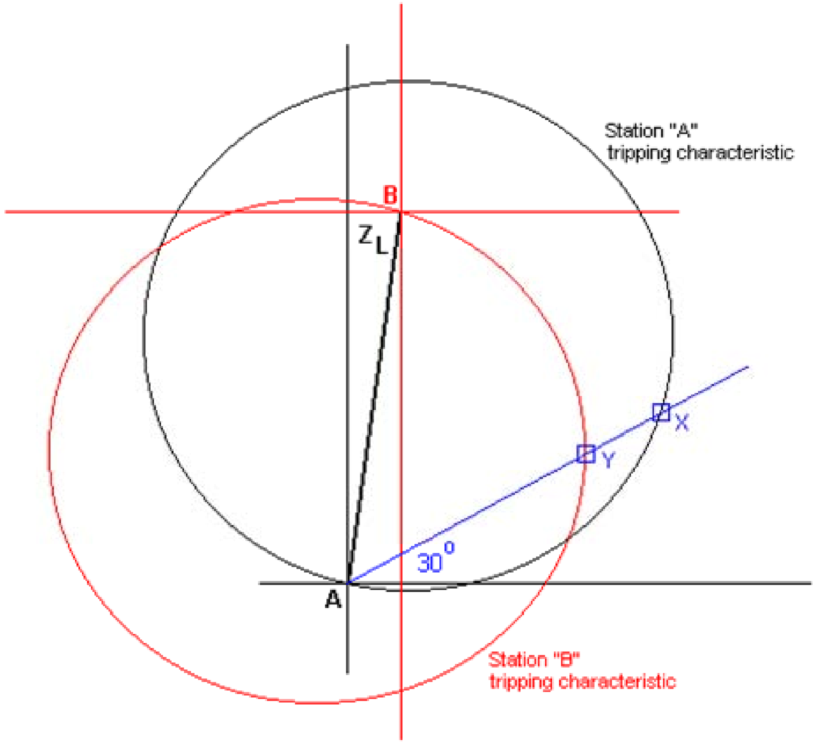



Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station "A" is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point "X" falls outside the tripping characteristic of the relay at Station "B", preventing tripping at either terminal. Relay "A" becomes susceptible to tripping along its 30-degree line only when point "Y" is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

## *Directional Comparison Blocking*

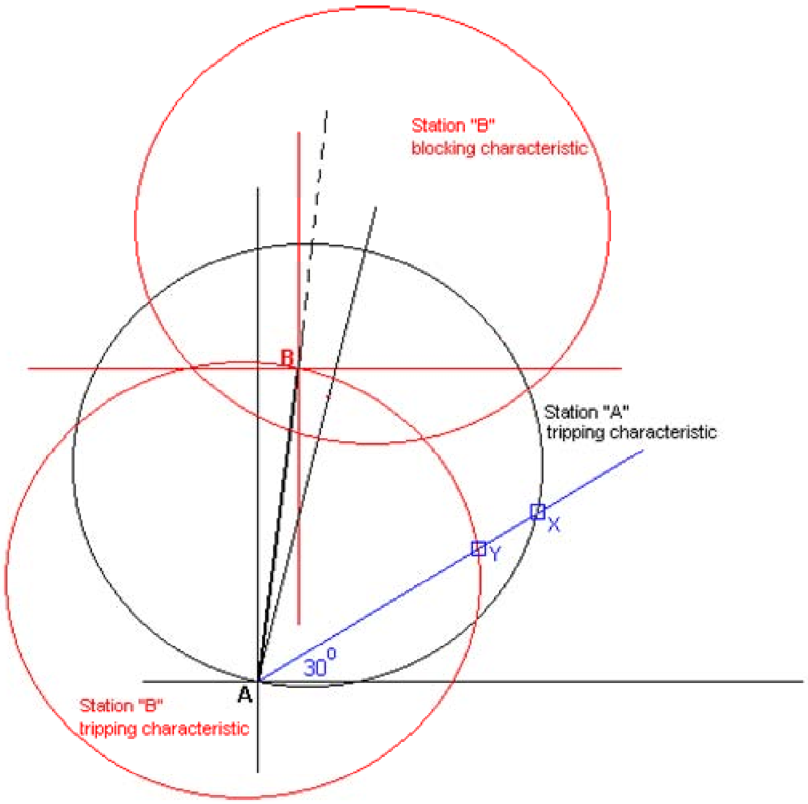



Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

# APPENDIX C — OUT-OF-STEP BLOCKING RELAYING

Out-of-step blocking is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability studies) or observed system swings.

There are many methods of providing the out-of-step blocking function; one common approach, used with distance tripping relays, uses a distance characteristic which is approximately concentric with the tripping characteristic. These characteristics may be circular mho characteristics, quadrilateral characteristics, or may be modified circular characteristics.

During normal system conditions the accelerating power, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa >> 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relative slowly at first; for a stable swing (where no generators "slip poles" or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure 1 below. .

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is approximately concentric to the related tripping relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to trip. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the tripping relay from operating.

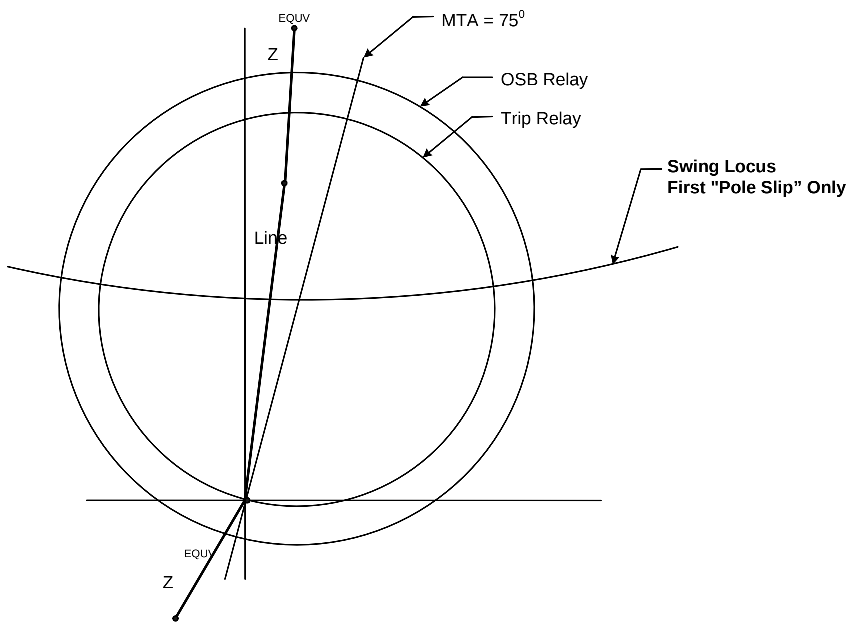



**Figure 1 –**

Figure 1 illustrates the relationship between the out-of-step blocking relay and the tripping relay, and shows a sample of a portion of an unstable swing.

## *Impact of System Loading of the Out-of-Step Relaying*

Figure 2 illustrates a tripping relay and out-of-step blocking relay, and shows the relative effects of several apparent impedances.

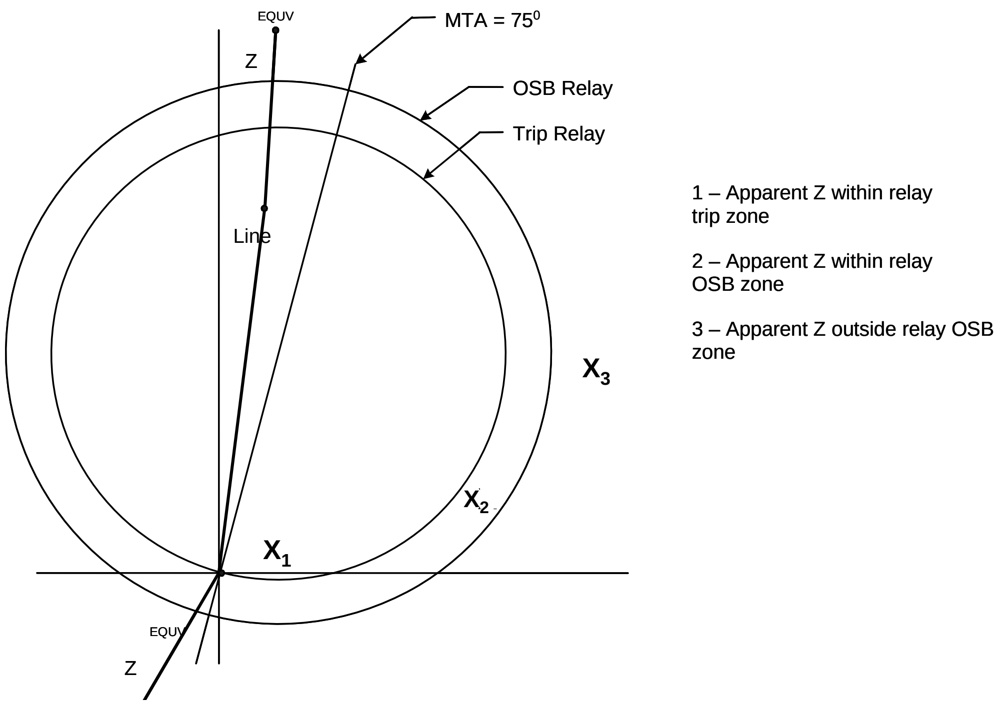



**Figure 2 – Out-of-Step Characteristics with Load**

Both the tripping relay and the out-of-step blocking relay have characteristics responsive to the impedance that is seen by the distance relay. In general, only the tripping relays are considered when evaluating the effect of system loads on relay characteristics (usually referred to as "relay loadability"). However, when the behavior of out-of-step blocking relays is considered, it becomes clear that they must also be included in the evaluation of system loads, as their reach must necessarily be longer than that of the tripping relays, making them even more responsive to load.

Three different load impedances are shown. Load impedance (1) shows an impedance (either load or fault) which would operate the tripping relay. Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic, and illustrates the desired result. The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the tripping relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time.

# APPENDIX D — SWITCH-ON-TO-FAULT SCHEME

Introduction

Switch-on-to-fault (SOTF) schemes (also known as “close-into-fault schemes or line-pickup schemes) are protection functions intended to trip a transmission line breaker when closed on to a faulted line. Dedicated SOTF schemes are available in various designs, but since the fault-detecting elements tend to be more sensitive than conventional, impedance-based line protection functions, they are designed to be “armed” only for a brief period following breaker closure. Depending on the details of scheme design and element settings, there may be implications for line relay loadability. This paper addresses those implications in the context of scheme design.

## *SOTF scheme applications*

SOTF schemes are applied for one or more of three reasons:

1. When an impedance-based protection scheme uses line-side voltage transformers, SOTF logic is required to detect a close-in, three-phase fault to protect against a line breaker being closed into such a fault. Phase impedance relays whose steady-state tripping characteristics pass through the origin on an R-X diagram will generally not operate if there is zero voltage applied to the relay before closing into a zero-voltage fault. This condition typically occurs during when a breaker is closed into a set of three-phase grounds which operations/maintenance personnel failed to remove prior to re-energizing the line. When this occurs in the absence of SOTF protection, the breaker will not trip, nor will breaker failure protection be initiated, possibly resulting in time-delayed tripping at numerous remote terminals. Unit instability and dropping of massive blocks of load can also occur.

   Current fault detector pickup settings must be low enough to allow positive fault detection under what is considered to be the “worst case” (highest) impedance to the source bus.

2. When an impedance protection scheme uses line-side voltage transformers, SOTF current fault detectors may operate significantly faster than impedance units when a breaker is closed into a fault anywhere on the line. The dynamic characteristics of typical impedance units are such that their speed of operation is impaired if polarizing voltages are not available prior to the fault.

   Current fault detector pickup settings will generally be lower in this application than in (1) above. The greater the coverage desired, and the longer the line, the lower the setting.

3. Regardless of voltage transformer location, SOTF schemes may allow high-speed clearing of faults along the entire line without having to rely or wait on a communications-aided tripping scheme.

   Current or impedance-based fault detectors must be set to reach the remote line terminal to achieve that objective.

## *SOTF line loadability considerations*

This reference document is intended to provide guidance for the review of existing SOTF schemes to

ensure that those schemes do not operate for non-SOTF conditions or under heavily stressed system conditions. This document also provides recommended practices for application of new SOTF schemes.

1 The SOTF protection must not operate assuming that the line terminals are closed at the outset and carrying up to 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

2 For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal.

## SOTF scheme designs

*1 Direct-tripping high-set instantaneous phase overcurrent*

This scheme is technically not a SOTF scheme, in that it is in service at all times, but it can be effectively applied under appropriate circumstances for clearing zero-voltage faults. It uses a continuously-enabled, high-set instantaneous phase overcurrent unit or units set to detect the fault under “worst case” (highest source impedance) conditions. The main considerations in the use of such a scheme involve detecting the fault while not overreaching the remote line terminal under external fault conditions, and while not operating for stable load swings. Under NERC line loadability requirements, the overcurrent unit setting also must be greater than 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

*2 Dedicated SOTF schemes*

Dedicated SOTF schemes generally include logic designed to detect an open breaker and to arm instantaneous tripping by current or impedance elements only for a brief period following breaker closing. The differences in the schemes lie (a) in the method by which breaker closing is declared, (b) in whether there is a scheme requirement that the line be dead prior to breaker closing, and (c) in the choice of tripping elements. In the case of modern relays, every manufacturer has its own design, in some cases with user choices for scheme logic as well as element settings.

In some SOTF schemes the use of breaker auxiliary contacts and/or breaker “close” signaling is included, which limits scheme exposure to actual breaker closing situations. With others, the breaker-closing declaration is based solely on the status of voltage and current elements. This is regarded as marginally less secure from misoperation when the line terminals are (and have been) closed, but can reduce scheme complexity when the line terminates in multiple breakers, any of which can be closed to energize the line.

## SOTF and Automatic Reclosing

With appropriate consideration of dead-line reclosing voltage supervision, there are no coordination issues between SOTF and automatic reclosing into a de-energized line. If pre-closing line voltage is the primary means for preventing SOTF tripping under heavy loading conditions, it is clearly desirable from a

security standpoint that the SOTF line voltage detectors be set to pick up at a voltage level below the automatic reclosing live-line voltage detectors and below 0.8 per-unit voltage.

Where this is not possible, the SOTF fault detecting elements are susceptible to operation for closing into an energized line, and should be set no higher than required to detect a close-in, three-phase fault under worst case (highest source impedance) conditions assuming that they cannot be set above 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023). Immunity to false tripping on high-speed reclosure may be enhanced by using scheme logic which delays the action of the fault detectors long enough for the line voltage detectors to pick up and instantaneously block SOTF tripping.

## Appendix E — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, *IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13, *American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)*, 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200

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**None.**

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability:**

**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2~~, Requirement 4~~:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

~~5.1.2 .~~

~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.~~

**5.2.** Requirement 3: First calendar quarter 18 months following applicable regulatory approvals; or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Relay settings for critical facilities added to the critical facility list pursuant to requirement R3.3 shall be set within 24 months of receipt of the notice from the Planning Coordinator. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

~~**R4.**Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1~~) and R4 )~~

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

1. Compliance Monitoring Process

**1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority**

~~1.1.1Regional Entity.~~

**1.1.1** ~~Compliance Enforcement Authority~~Regional Entity for all responsible entities except those responsible entities that work for the Regional Entity

**1.1.2** ERO for all responsible entities that work for the Regional Entity

**1.2. ~~Compliance Monitoring Period and~~Violation Reset Time ~~Frame~~Period**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification ~~or~~, compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance ~~Monitor~~Enforcement Authority.

**2. Violation Severity Levels (R1, R2): Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 ~~thought~~through R1.13

**2.4.2** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels (R3): Planning Coordinator**

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

**3.4.2** Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## ~~F.Associated Documents~~

## F. Supplemental Technical Reference Document

~~The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies~~

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**3.8.** Relay elements associated with DC lines.

**3.9.** Relay elements associated with DC converter transformers.

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2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

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5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2:

   **5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.

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**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Relay settings for critical facilities added to the critical facility list pursuant to requirement R3.3 shall be set within 24 months of receipt of the notice from the Planning Coordinator. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

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**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Enforcement Authority**

**1.1.1** Regional Entity for all responsible entities except those responsible entities that work for the Regional Entity

**1.1.2** ERO for all responsible entities that work for the Regional Entity

**1.2. Violation Reset Time Period**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels (R1, R2): Transmission Owner, Generator Owner, and Distribution Provider**

**2.1. Lower:** Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

**2.2. Moderate:** Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

**2.3. High:** NA

**2.4. Severe:** There shall be a severe violation severity level if either of the following conditions exist:

**2.4.1** Relay settings do not comply with any of the requirements in R1.1 through R1.13

**2.4.2** Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

**3. Violation Severity Levels (R3): Planning Coordinator**

**3.1. Lower:** N/A

**3.2. Moderate:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

**3.3. High:** Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

**3.4. Severe:** There shall be a severe violation severity level if any of the following conditions exist:

**3.4.1** Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

**3.4.2** Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

**3.4.3** Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

**Maureen E. Long**
Standards Process Manager

November 19, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

**Announcement:**
**Initial Ballot Window, Pre-ballot Review Period and Ballot Pool Open**

**The Standards Committee (SC) announces the following standards actions:**

## Initial Ballot Window for PRC-023 — Relay Loadability is Open

The initial ballot for the PRC-023-1 — Relay Loadability is open and will remain open until 8 p.m. Tuesday, December 4, 2007.

This standard was developed to address the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called 'zone 3 relay' issue, which has been expanded to address other protection devices subject to unintended operation during extreme system conditions. The proposed standard establishes minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

The ballot for this standard also includes the Relay Loadability Implementation Plan.

## Pre-ballot Window for Revised Interpretation of BAL-005 Requirement R17 (for PGE) is Open

Portland General Electric Company submitted a Request for an Interpretation of BAL-005-1 Automatic Generation Control Requirement R17. The Interpretation asked if the requirement to annually check and calibrate time error and frequency devices applies to the following measuring devices:

- Only equipment within the operations control room
- Only equipment that provides values used to calculate automatic generation control area control error
- Only equipment that provides values to its SCADA system
- Only equipment owned or operated by the balancing authority
- Only to new or replacement equipment
- To all equipment that a balancing authority owns or operates

The Frequency Task Force (drafting team) provided an interpretation that underwent an initial ballot from October 18 through October 29, 2007. Some comments submitted with ballots indicated that the clarification seemed to expand the scope of the associated requirement and the drafting team added some clarifying language to the interpretation. The drafting team is re-posting the revised interpretation for a **new** 30-day pre-ballot review.

The revised interpretation clarifies that Requirement R17 applies only to the time error and frequency devices that provide, or in the case of backup equipment may provide, input into the ACE equation or provide real-time time error or frequency information to the system operator. The requirement does not apply to frequency inputs from other sources that are for reference only. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the balancing authority; however the balancing authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in Requirement 17 — the other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

The ballot pool to vote on this interpretation has been re-opened and will remain open up until 8 a.m. (EST) Wednesday, December 19, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp-interp_bal-005_pge_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Wednesday, December 19, 2007.

**Standards Development Process**

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

## Compliance with Standards

Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

## Proposed Effective Dates

Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply:
  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2:
  - For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.
  - For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals or, , in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.
- Requirement 3: At the beginning the first calendar quarter 18 months after applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

## Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

## Modified Standards

There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

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  1. The approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and
  2. The non-conforming relay settings are mitigated according to the approved mitigation plan.
- Requirement 1, Requirement 2~~, Requirement 4~~:
  - For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.
  - For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter ~~42~~ 39 months after applicable regulatory approvals or, , in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.
- Requirement 3: At the beginning the first calendar quarter 18 months after applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

# PRC-023 Reference

# Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Corporation

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

***Version 1.0***

***January 9, 2007***



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# Table of Contents

# Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Protection systems intended for protection during stable power swings
   - 2.4. Generator protection relays that are susceptible to load
   - 2.5. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017. Protection systems that are

designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

2.6. Relay elements associated with DC lines

2.7. Relay elements associated with DC converter transformers

# Requirements Reference Material

## R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

## R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L\text{-}L}$ = Rated line-to-line voltage

$I_{rating}$ = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating ($I_{rating}$) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

## R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been

determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating ($I_{rating}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

## R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

### R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

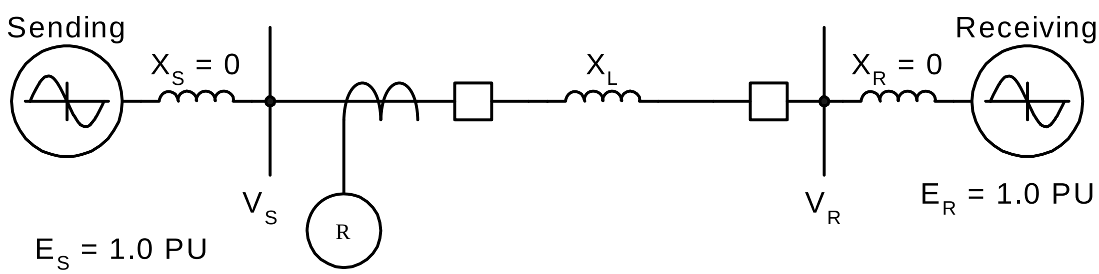



**Figure 1 – Maximum Power Transfer**

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$\delta$ = Voltage angle between $V_S$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$I_{real}$ = Real component of current

$V$ = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{\mathrm{I_{total}} = \frac{0.816 \times \mathrm{V}}{\mathrm{X_L}}}$$

Where:

$I_{total}$ is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$ (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

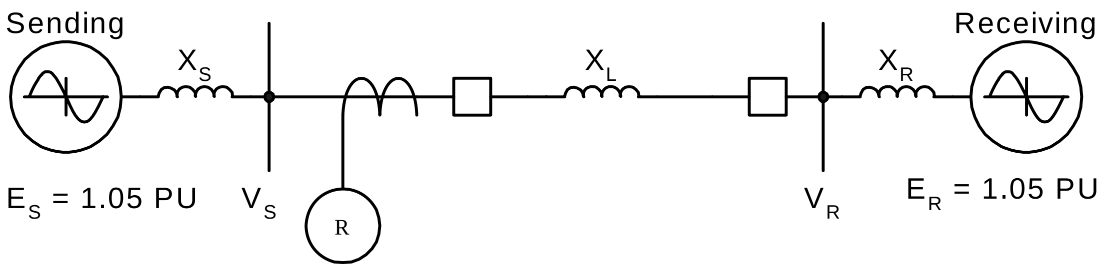



**Figure 2 – Site-Specific Maximum Power Transfer Limit**

The recommended procedure for determining $X_S$ and $X_R$ is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude ($I_{real}$) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

$V$ = Nominal phase-to-phase system voltage

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{\left(X_S + X_R + X_L\right)}}$$

Where:

$I_{total}$ = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

## R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess

of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

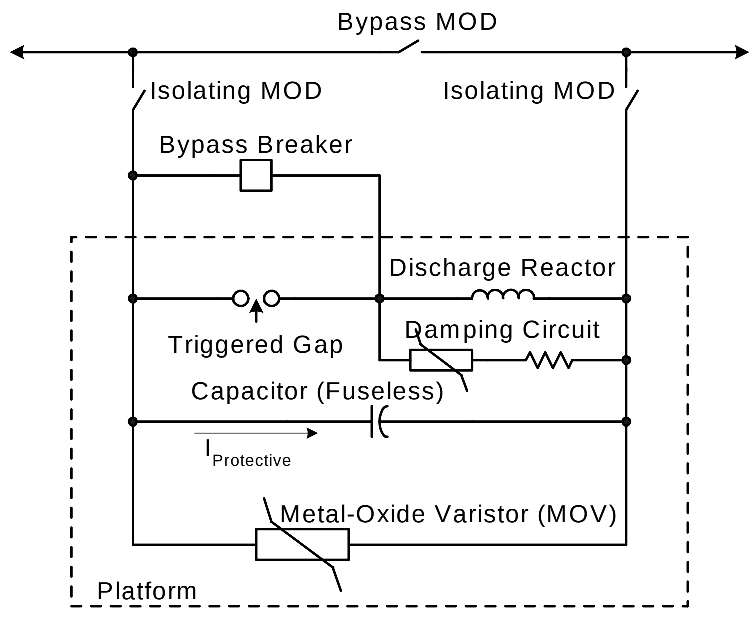



**Figure 3 – Series Capacitor Components**

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

$X_C$ = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because $I_{total}$, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. $I_{total}$ (where $I_{total}$ is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

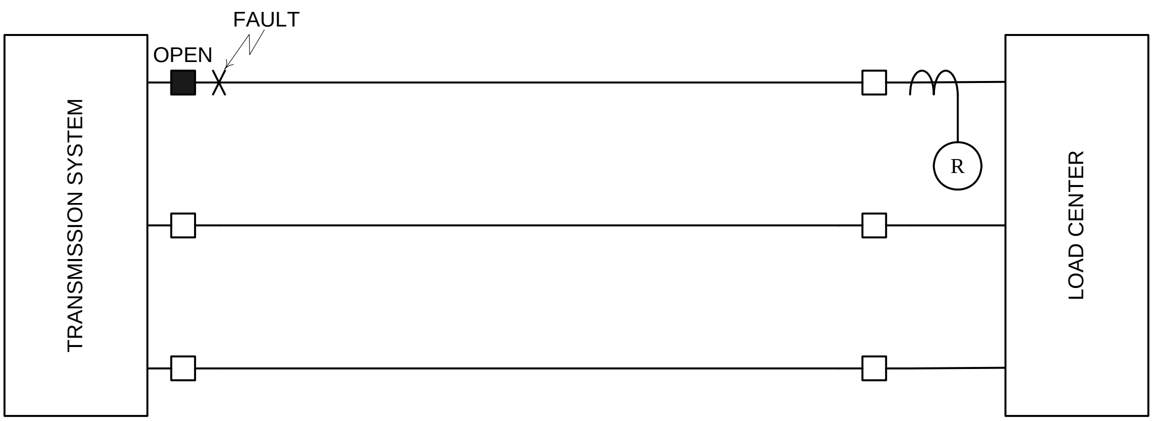



**Figure 4 – Weak Source Systems**

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{{V_S}^2 + {V_R}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$\mathrm{I_{max}} = 1.15 \times \sqrt{2} \times 1.05 \times \mathrm{I_{fault}}$$

$$I_{\max} = 1.71 \times I_{fault}$$

Where:

> $I_{fault}$ is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times $I_{fault}$, where $I_{fault}$ is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

## R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current ($I_{max}$) that the line will experience.

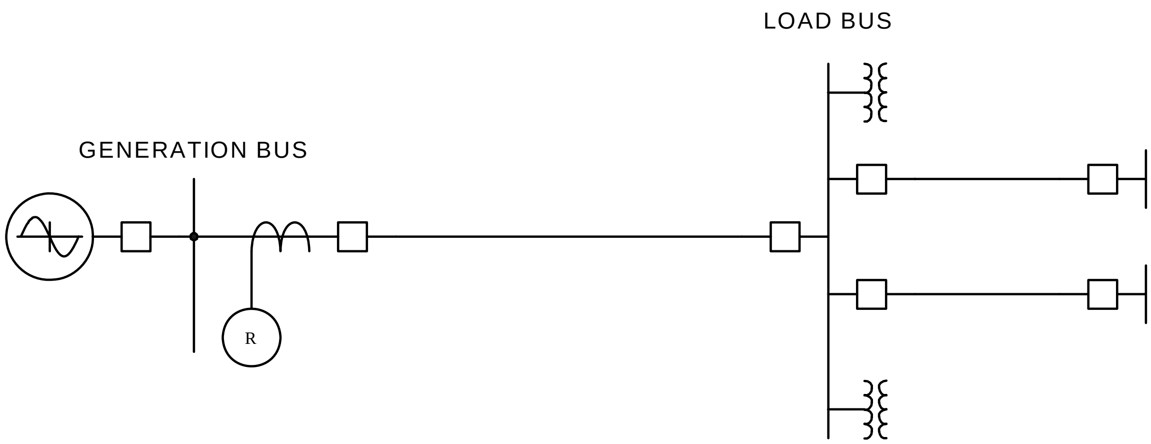



**Figure 5 – Generation Remote to Load Center**

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amperes at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$\boxed{I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}}$$

Where:

$V_{relay}$ = Phase-to-phase voltage at the relay location

$N$ = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the $I_{max}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

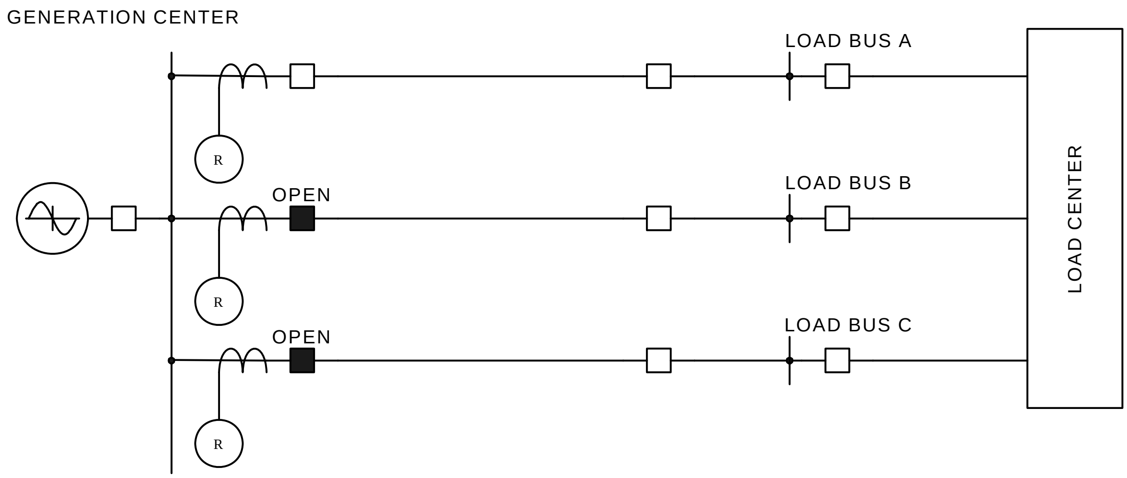



**Figure 6 – Generation Connected to System – Multiple Lines**

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The $I_{max}$ expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds $I_{max}$.

Set the tripping relay so it does not operate at or below 1.15 times $I_{max}$, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

## R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

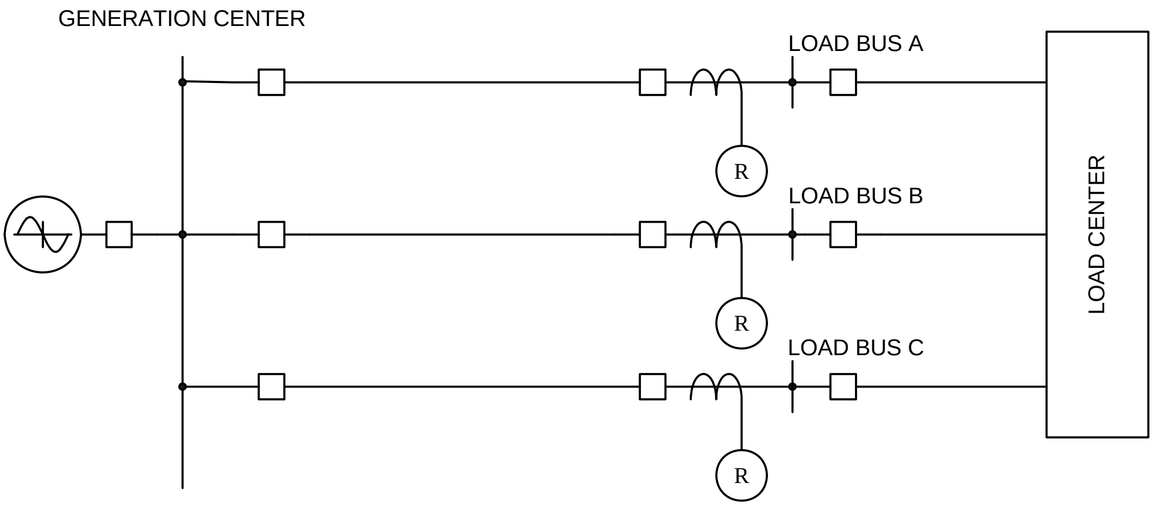



**Figure 7 – Load Remote to Generation**

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow ($I_{max}$) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

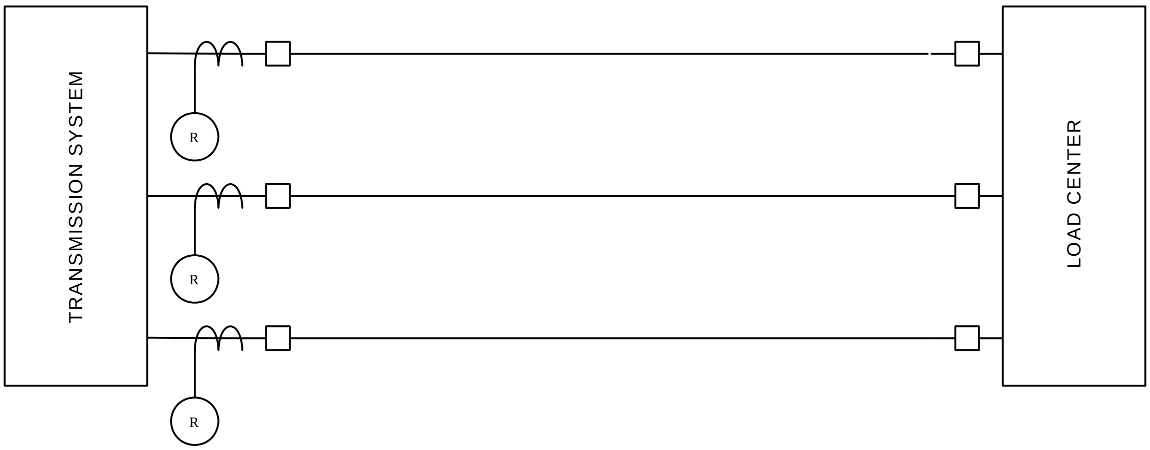



**Figure 8 – Remote Cohesive Load Center**

Also, one must determine the maximum power flow on an individual line to the area ($I_{max}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.

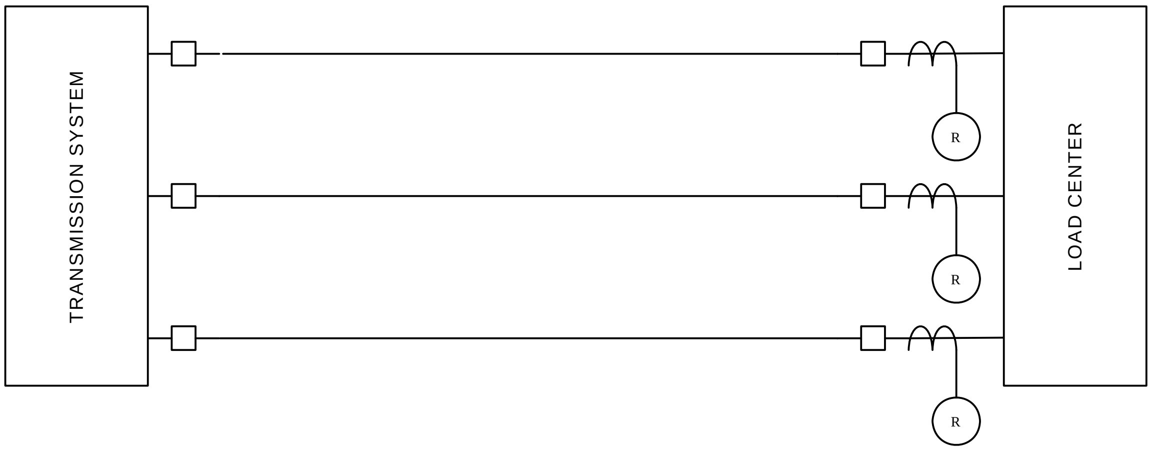



**Figure 9 – Cohesive Load Center Remote to Transmission System**

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow ($I_{max}$)from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

## R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer, and addresses protection that is intended to protect the transformer from thermal overloads.

1. Set the overload protection relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator-established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload, or
2. Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting shall be no less than 100° C for the top oil or 140° C[5] for the winding hot spot temperature.

## R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not “overly sensitive,” and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

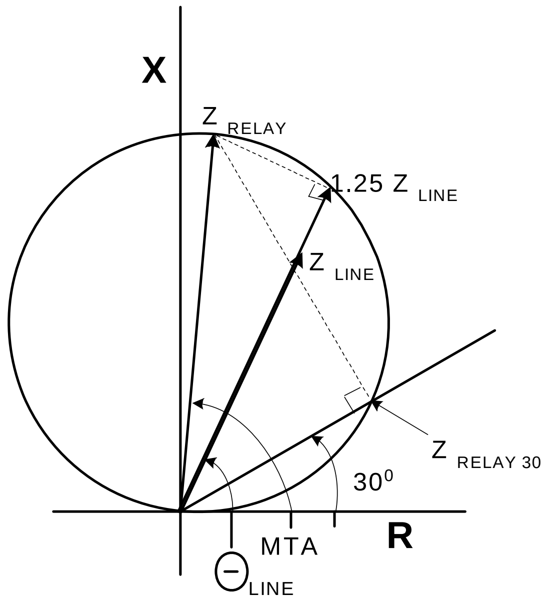



**Figure 10 – Long Line relay Loadability**

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{line}$ = Line impedance

$\Theta_{line}$ = Line impedance angle

$Z_{relay}$ = Relay setting at the maximum torque angle

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[ \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})} \right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos( MTA - \Theta_{line} )}{\sqrt{3} \times 1.25 \times Z_{line} \times cos( MTA - 30° )}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

## R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

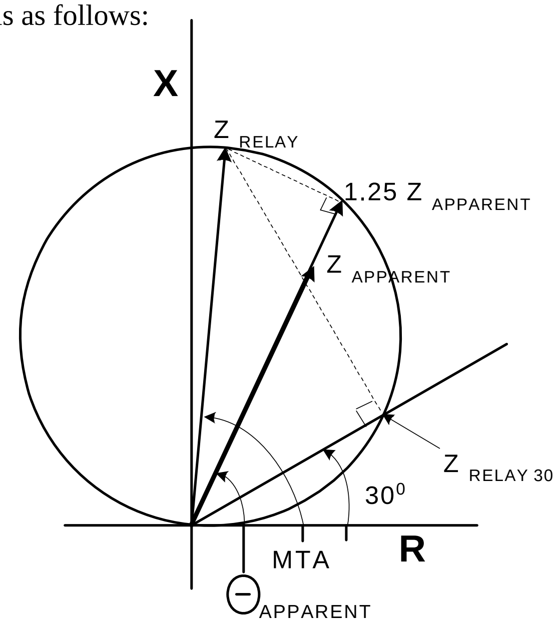



**Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps**

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

$Z_{relay}$ = Relay setting at the maximum torque angle.

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

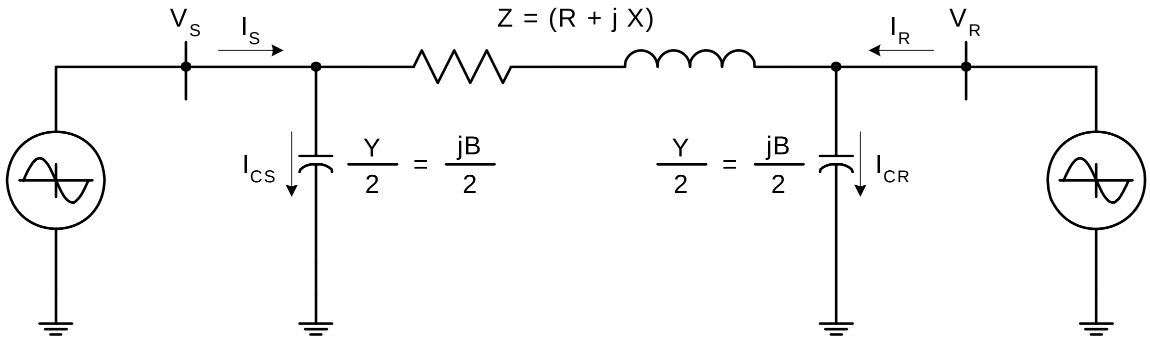
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

# Appendices

# Appendix A — Long Line Maximum Power Transfer Equations




Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{{V_S}^2}{|Z|}\cos(\theta^\circ) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta^\circ)$$

$$Q_{S3-\phi} = \frac{{V_S}^2}{|Z|}\sin(\theta^\circ) - {V_S}^2 \frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta^\circ)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos(\theta^\circ) + \sin(\theta^\circ)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta^\circ) - |Z|\frac{B}{2} - \cos(\theta^\circ)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{{I_{real}}^2 + {I_{reactive}}^2}}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$V$ = Nominal phase-to-phase bus voltage

$\delta$ = Voltage angle between $V_S$ and $V_R$

$Z$ = Reactance, including fixed shunt reactors, of the transmission line in ohms*

$\Theta$ = Line impedance angle

$B$ = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

# Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

### *Unmodified Permissive Overreaching Transfer Trip*

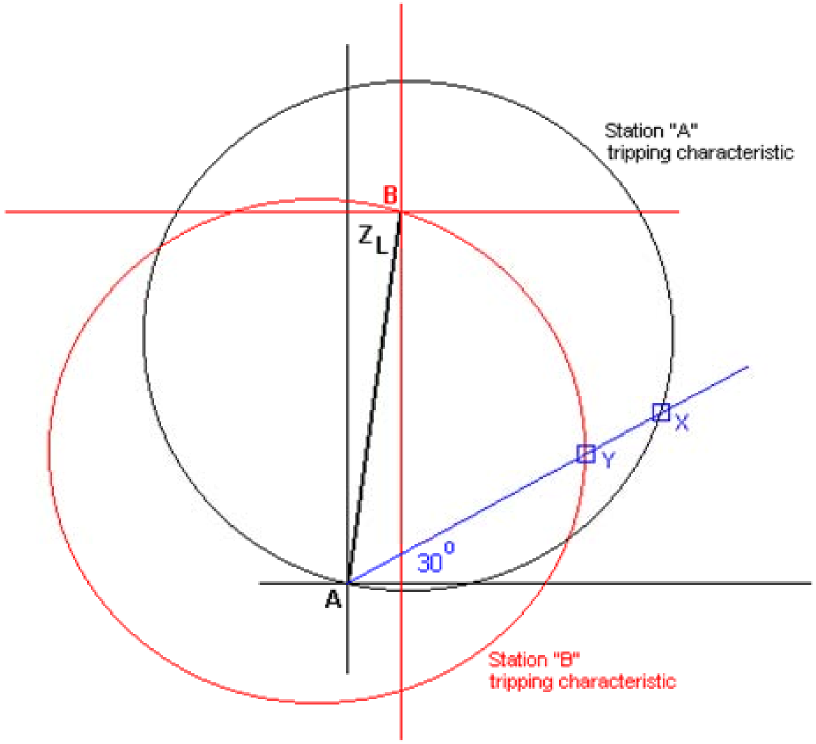



Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station "A" is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point "X" falls outside the tripping characteristic of the relay at Station "B", preventing tripping at either terminal. Relay "A" becomes susceptible to tripping along its 30-degree line only when point "Y" is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

## *Directional Comparison Blocking*

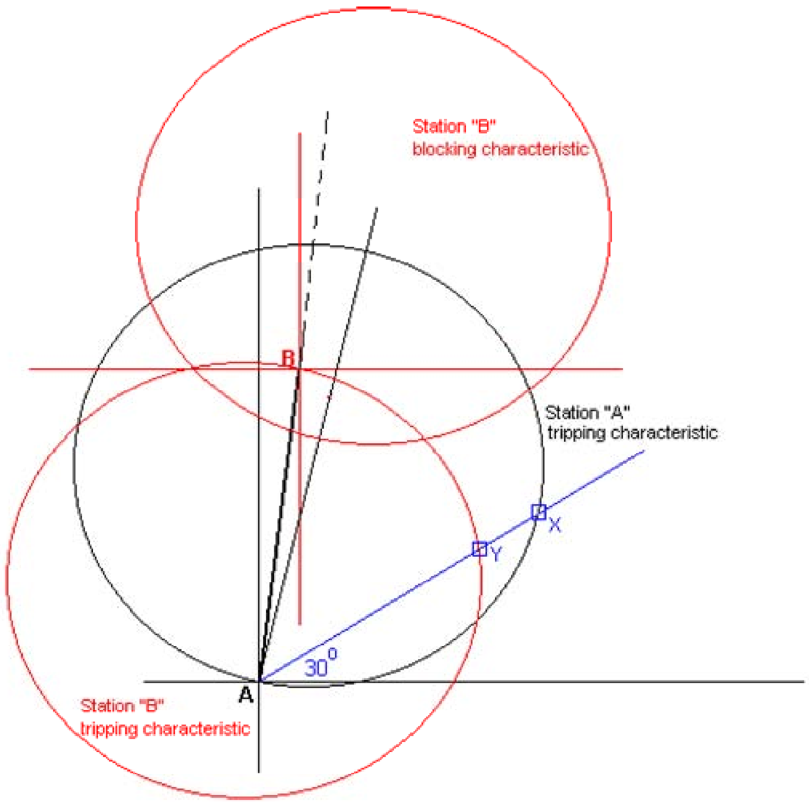



Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

# APPENDIX C — OUT-OF-STEP BLOCKING RELAYING

Out-of-step blocking is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability studies) or observed system swings.

There are many methods of providing the out-of-step blocking function; one common approach, used with distance tripping relays, uses a distance characteristic which is approximately concentric with the tripping characteristic. These characteristics may be circular mho characteristics, quadrilateral characteristics, or may be modified circular characteristics.

During normal system conditions the accelerating power, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa >> 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relative slowly at first; for a stable swing (where no generators “slip poles” or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure 1 below. .

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is approximately concentric to the related tripping relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to trip. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the tripping relay from operating.

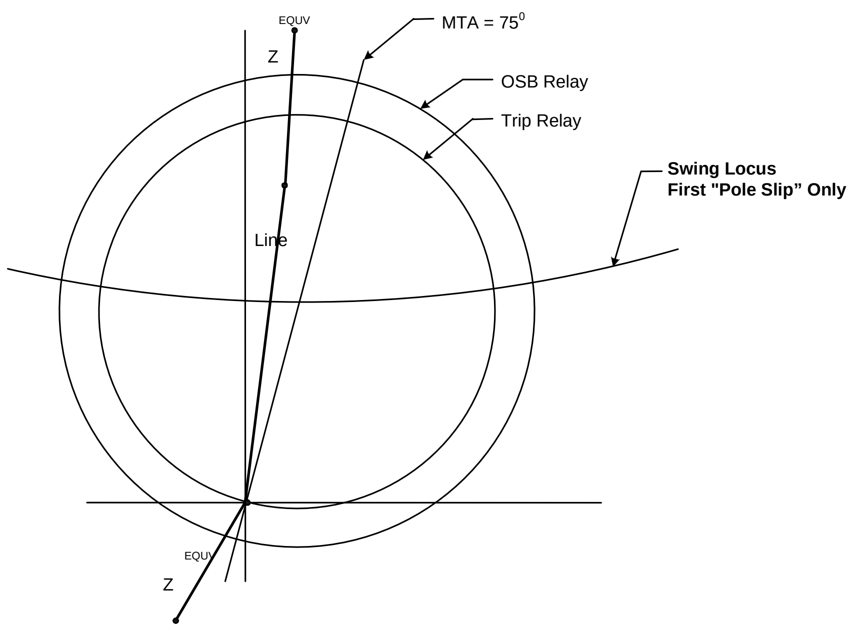



**Figure 1 –**

Figure 1 illustrates the relationship between the out-of-step blocking relay and the tripping relay, and shows a sample of a portion of an unstable swing.

### *Impact of System Loading of the Out-of-Step Relaying*

Figure 2 illustrates a tripping relay and out-of-step blocking relay, and shows the relative effects of several apparent impedances.

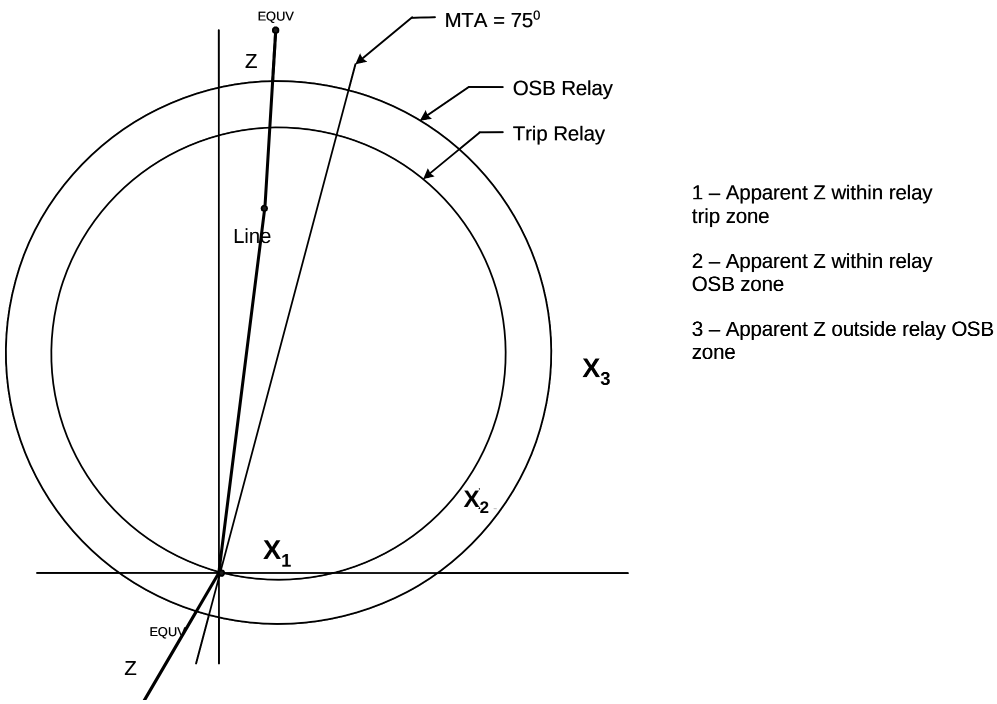



**Figure 2 – Out-of-Step Characteristics with Load**

Both the tripping relay and the out-of-step blocking relay have characteristics responsive to the impedance that is seen by the distance relay. In general, only the tripping relays are considered when evaluating the effect of system loads on relay characteristics (usually referred to as "relay loadability"). However, when the behavior of out-of-step blocking relays is considered, it becomes clear that they must also be included in the evaluation of system loads, as their reach must necessarily be longer than that of the tripping relays, making them even more responsive to load.

Three different load impedances are shown. Load impedance (1) shows an impedance (either load or fault) which would operate the tripping relay. Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic, and illustrates the desired result. The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the tripping relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time.

# APPENDIX D — SWITCH-ON-TO-FAULT SCHEME

Introduction

Switch-on-to-fault (SOTF) schemes (also known as “close-into-fault schemes or line-pickup schemes) are protection functions intended to trip a transmission line breaker when closed on to a faulted line. Dedicated SOTF schemes are available in various designs, but since the fault-detecting elements tend to be more sensitive than conventional, impedance-based line protection functions, they are designed to be “armed” only for a brief period following breaker closure. Depending on the details of scheme design and element settings, there may be implications for line relay loadability. This paper addresses those implications in the context of scheme design.

## *SOTF scheme applications*

SOTF schemes are applied for one or more of three reasons:

1. When an impedance-based protection scheme uses line-side voltage transformers, SOTF logic is required to detect a close-in, three-phase fault to protect against a line breaker being closed into such a fault. Phase impedance relays whose steady-state tripping characteristics pass through the origin on an R-X diagram will generally not operate if there is zero voltage applied to the relay before closing into a zero-voltage fault. This condition typically occurs during when a breaker is closed into a set of three-phase grounds which operations/maintenance personnel failed to remove prior to re-energizing the line. When this occurs in the absence of SOTF protection, the breaker will not trip, nor will breaker failure protection be initiated, possibly resulting in time-delayed tripping at numerous remote terminals. Unit instability and dropping of massive blocks of load can also occur.

   Current fault detector pickup settings must be low enough to allow positive fault detection under what is considered to be the “worst case” (highest) impedance to the source bus.

2. When an impedance protection scheme uses line-side voltage transformers, SOTF current fault detectors may operate significantly faster than impedance units when a breaker is closed into a fault anywhere on the line. The dynamic characteristics of typical impedance units are such that their speed of operation is impaired if polarizing voltages are not available prior to the fault.

   Current fault detector pickup settings will generally be lower in this application than in (1) above. The greater the coverage desired, and the longer the line, the lower the setting.

3. Regardless of voltage transformer location, SOTF schemes may allow high-speed clearing of faults along the entire line without having to rely or wait on a communications-aided tripping scheme.

   Current or impedance-based fault detectors must be set to reach the remote line terminal to achieve that objective.

## *SOTF line loadability considerations*

This reference document is intended to provide guidance for the review of existing SOTF schemes to

ensure that those schemes do not operate for non-SOTF conditions or under heavily stressed system conditions. This document also provides recommended practices for application of new SOTF schemes.

1 The SOTF protection must not operate assuming that the line terminals are closed at the outset and carrying up to 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

2 For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal.

### SOTF scheme designs

*1 Direct-tripping high-set instantaneous phase overcurrent*

This scheme is technically not a SOTF scheme, in that it is in service at all times, but it can be effectively applied under appropriate circumstances for clearing zero-voltage faults. It uses a continuously-enabled, high-set instantaneous phase overcurrent unit or units set to detect the fault under "worst case" (highest source impedance) conditions. The main considerations in the use of such a scheme involve detecting the fault while not overreaching the remote line terminal under external fault conditions, and while not operating for stable load swings. Under NERC line loadability requirements, the overcurrent unit setting also must be greater than 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023), when calculated in accordance with the methods described in this standard.

*2 Dedicated SOTF schemes*

Dedicated SOTF schemes generally include logic designed to detect an open breaker and to arm instantaneous tripping by current or impedance elements only for a brief period following breaker closing. The differences in the schemes lie (a) in the method by which breaker closing is declared, (b) in whether there is a scheme requirement that the line be dead prior to breaker closing, and (c) in the choice of tripping elements. In the case of modern relays, every manufacturer has its own design, in some cases with user choices for scheme logic as well as element settings.

In some SOTF schemes the use of breaker auxiliary contacts and/or breaker "close" signaling is included, which limits scheme exposure to actual breaker closing situations. With others, the breaker-closing declaration is based solely on the status of voltage and current elements. This is regarded as marginally less secure from misoperation when the line terminals are (and have been) closed, but can reduce scheme complexity when the line terminates in multiple breakers, any of which can be closed to energize the line.

### SOTF and Automatic Reclosing

With appropriate consideration of dead-line reclosing voltage supervision, there are no coordination issues between SOTF and automatic reclosing into a de-energized line. If pre-closing line voltage is the primary means for preventing SOTF tripping under heavy loading conditions, it is clearly desirable from a

security standpoint that the SOTF line voltage detectors be set to pick up at a voltage level below the automatic reclosing live-line voltage detectors and below 0.8 per-unit voltage.

Where this is not possible, the SOTF fault detecting elements are susceptible to operation for closing into an energized line, and should be set no higher than required to detect a close-in, three-phase fault under worst case (highest source impedance) conditions assuming that they cannot be set above 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023). Immunity to false tripping on high-speed reclosure may be enhanced by using scheme logic which delays the action of the fault detectors long enough for the line voltage detectors to pick up and instantaneously block SOTF tripping.

## Appendix E — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, *IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13, *American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz),* 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200

**Maureen E. Long**
Standards Process Manager

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 6, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

## Announcement: Initial Ballot Results for Transmission Relay Loadability Standard

**The Standards Committee (SC) announces the following:**

### Initial Ballot Results for PRC-023-1 — Transmission Relay Loadability

The initial ballot for PRC-023-1 — Transmission Relay Loadability and its associated Implementation Plan, was conducted from November 19 through December 4, 2007.

This proposed standard addresses the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called "zone 3 relay" issue, expanded to address other protection devices subject to unintended operation during extreme system conditions. The proposed standard establishes minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the standard needs modification before proceeding to a recirculation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 91.83 %
Approval: 80.84 %

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

**Reliability Standards**



| Ballot Results | |
|---|---|
| **Ballot Name:** | Standard PRC-023-1 - Transmission Relay Loadability_in |
| **Ballot Period:** | 11/19/2007 - 12/4/2007 |
| **Ballot Type:** | Initial |
| **Total # Votes:** | 191 |
| **Total Ballot Pool:** | 208 |
| **Quorum:** | **91.83 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 80.84 % |
| **Ballot Results:** | **The standard will proceed to recirculation ballot.** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 68 | 1 | 46 | 0.767 | 14 | 0.233 | 3 | 5 |
| 2 - Segment 2. | 10 | 0.7 | 5 | 0.5 | 2 | 0.2 | 1 | 2 |
| 3 - Segment 3. | 52 | 1 | 33 | 0.805 | 8 | 0.195 | 5 | 6 |
| 4 - Segment 4. | 10 | 0.9 | 7 | 0.7 | 2 | 0.2 | 0 | 1 |
| 5 - Segment 5. | 29 | 1 | 19 | 0.792 | 5 | 0.208 | 3 | 2 |
| 6 - Segment 6. | 20 | 1 | 14 | 0.737 | 5 | 0.263 | 1 | 0 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 1 | 0.1 | 0 | 0 | 1 | 0.1 | 0 | 0 |
| 9 - Segment 9. | 10 | 0.9 | 9 | 0.9 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.6 | 6 | 0.6 | 0 | 0 | 1 | 0 |
| **Totals** | **208** | **7.3** | **140** | **5.901** | **37** | **1.399** | **14** | **17** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | AEP Service Corp. -- Transmission System AEP | Scott P. Moore | Affirmative | |
| 1 | Allegheny Power | Rodney Phillips | Affirmative | |
| 1 | Alliant Energy | Kenneth Goldsmith | Affirmative | |
| 1 | AltaLink Management Ltd. | Rick Spyker | Affirmative | |
| 1 | American Public Power Association | E. Nick Henery | | |
| 1 | American Transmission Company, LLC | Jason Shaver | Negative | View |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | CenterPoint Energy | Paul Rocha | | |
| 1 | Central Maine Power Company | David Mark Conroy | | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Dairyland Power Coop. | Robert W. Roddy | Affirmative | |
| 1 | Dominion Virginia Power | William L. Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Doug Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | Affirmative | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Negative | View |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | JEA | Ted E. Hobson | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Affirmative | |
| 1 | Keyspan LIPA | Richard J. Bolbrock | Affirmative | |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Affirmative | |
| 1 | Lower Colorado River Authority | Martyn Turner | Affirmative | |
| 1 | Manitoba Hydro | Robert G. Coish | Negative | View |
| 1 | Minnesota Power, Inc. | Carol Gerou | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | View |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Melvin H. Perkins | Affirmative | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Affirmative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Abstain | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Negative | View |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Negative | View |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwestern Power Administration | Mike Wech | Negative | |

| | | | | |
|---|---|---|---|---|
| 1 | Texas Municipal Power Agency | Frank J. Owens | Affirmative | |
| 1 | Tri-State G & T Association Inc. | Bruce A Sembrick | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | |
| 1 | Westar Energy | Allen Klassen | | |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Negative | View |
| 2 | Alberta Electric System Operator | Anita Lee | | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Negative | View |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Abstain | |
| 2 | Independent Electricity System Operator | Don Tench | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Affirmative | View |
| 2 | New Brunswick System Operator | Alden Briggs | Negative | View |
| 2 | New York Independent System Operator | Gregory Campoli | | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Allegheny Power | Bob Reeping | Affirmative | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Negative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Consumers Energy Co. | David A. Lapinski | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Negative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Negative | View |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | JEA | Garry Baker | Affirmative | |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | Affirmative | View |
| 3 | Lincoln Electric System | Bruce Merrill | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | | |
| 3 | Manitoba Hydro | Ronald Dacombe | Negative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Affirmative | |

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|---|---|---|---|---|
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Abstain | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | | |
| 3 | Public Utility District No. 1 of Chelan County | Kenneth R. Johnson | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Reliant Energy Services | John Meyer | | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | San Diego Gas & Electric | Scott Peterson | | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | Affirmative | |
| 3 | Turlock Irrigation District | Casey Hashimoto | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Affirmative | |
| 3 | Xcel Energy, Inc. | Michael Ibold | Negative | View |
| 4 | American Municipal Power - Ohio | Chris Norton | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Affirmative | |
| 4 | North Carolina Municipal Power Agency #1 | Andrew Fusco | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Oklahoma Municipal Power Authority | Robin J. Morecroft | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Transmission Access Policy Study Group | William J. Gallagher | | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Affirmative | |
| 5 | Alabama Electric Coop. Inc. | Tim Hattaway | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | City of Tallahassee | Alan Gale | Abstain | View |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Dairyland Power Coop. | Warren Schaefer | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Affirmative | |
| 5 | Lincoln Electric System | Dennis Florom | Affirmative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Negative | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | PSEG Power LLC | Thomas Piascik | | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southeastern Power Administration | Douglas Spencer | Abstain | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |

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|---|---|---|---|---|
| 5 | Tenaska, Inc. | Scott M. Helyer | Affirmative | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Affirmative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Negative | View |
| 6 | AEP Service Corp. | Dana E. Horton | Negative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Consolidated Edison Co. of New York | Rebecca Adrienne Craft | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Abstain | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | First Energy Solutions | Alfred G. Roth | Affirmative | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | Affirmative | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Negative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Affirmative | |
| 6 | Southern Company Generation and Energy Marketing | J. Roman Carter | Affirmative | |
| 6 | Western Area Power Administration - UGP Marketing | John Stonebarger | Affirmative | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Negative | View |
| 7 | Eastman Chemical Company | Lloyd Webb | Affirmative | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Negative | View |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | California Public Utilities Commission | Laurence Chaset | | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | Maryland Public Service Commission | James Schafer | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | New York State Public Service Commission | James T. Gallagher | Affirmative | |
| 9 | North Carolina Utilities Commission | Kimberly J. Jones | Affirmative | |
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Gerry W. Cauley | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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116-390 Village Boulevard, Princeton, New Jersey 08540-5721

# Consideration of Comments on Initial Ballot of PRC-023-1 — Transmission Relay Loadability

**Summary Consideration:**

Several typographical and editorial changes were made in response to comments; however the changes do not alter the technical content of the standard nor do they change the content or intent of any of the requirements or compliance elements of the standard.

Some commenters raised issue with regard to the threshold used to define the applicability of facilities subject to the requirements in this standard. Most stakeholders agreed with the applicability of the proposed standard. While the SDT acknowledges that the threshold may not be unanimously supported, it is an acceptable "starting point" for the application of this new set of requirements. If additional research is conducted that leads to a better threshold for identifying the facilities that should be applicable to the standard, then a new SAR can be developed to refine the applicability of the standard. At this point, the SDT believes that reliability is better protected by moving the standard forward with the proposed applicability – the intent of this set of requirements is to ensure that certain relays are set so they do not contribute to a cascading event such as the August 2003 disturbance.

Several commenters suggested that the word, "critical" should not be used in the standard. The SDT deliberately avoided capitalizing the word, "critical" in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, "Critical Asset". When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary.

**Appeals Process:**

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

| Entity | Segment | Comment |
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| American Transmission Company, LLC | 1 | The word "critical" should be removed from Requirement 3 because of the confusion it will create with other existing standards. The removal of this word will not impact that substance of the requirement but will clarify that any list developed by the PC only applies to PRC-023. ATC offers the following modification: "The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area should be subject to Requirement 1 and 2 in order to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability." |
| **Response:** The SDT thanks the commenter for the offered revision. In this instance, the SDT did not use the capitalized form of the word, “critical” - in this standard. The SDT deliberately avoided capitalizing the word, “critical” in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, “Critical Asset”. When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary. | | |
| Bonneville Power Administration | 1 | While we agree with the intent of this standard, we believe it is more conservative than necessary in order to meet the goal of preventing a relay action to trip a line under non-fault loading. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| FirstEnergy Energy Delivery | 1 | FirstEnergy (FE) appreciates the hard work put forth by NERC’s Relay Loadability Standard Drafting Team. However, at this time, FE is voting NO to the standard as written and asks that NERC consider our following questions, comments, and suggestions. Issues ?<br><br>1. We do not agree with the Violation Severity Levels (VSL) as written. First, we believe the VSLs should be reformatted to match the table format as presented in the NUC-001 and ATC/TTC standards that are presently out for comment. The Relay Loadability team has grouped the VSLs inconsistent with the NUC and ATC standard and we firmly believe that the table format is a much better method of mapping the VSLs with the requirements.<br><br>2. Also, we propose modified wording for the Moderate VSL for R1 in an effort to make the VSL clearer. We have included a proposed table format and red-line on Pg. 2 of these comments.<br><br>3. Regarding Part D, Sec. 1.4 (Additional Compliance Information), we do not agree with the requirement for annual self-certification because it only creates more work for the entities and does not add value to monitoring of reliability. Relay loadability schemes do not change enough to warrant annual certification. We suggest changing the required self-certification to every two years. ?<br><br>4. Page X in Appendix D of the Reference Document seems to mandate a 75% voltage limit for SOTF supervision for newer protection schemes. This reference is under point #2 in the section titled SOTF line loadability considerations. |

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| | | This requirement is not present in the proposed standard and we believe it should not be present in the Reference Document. We propose eliminating the second sentence from point #2 in that section of the Reference Document. ?<br><br>5. There are several references to "critical" facilities in the standard. It is not clear what criteria would be used to determine a "critical" facility in the context of requirements related to relay settings. We believe this term should be modified and should be limited to the CIP standards and not used in this standard. Other Comments/Suggestions ?<br><br>6. Per Part F of the standard regarding the PRC-023 Reference Document "Determination and Application of Practical Relaying Loadability Ratings", it is FE's interpretation that this document is strictly a "guide" for use in helping understand how to calculate this data and not enforceable and mandatory, correct? Our interpretation aligns with NERC's Reliability Standards Development Procedure Version 6.1, on pg.9 under "Supporting References" which states that Standard supplements "are not themselves mandatory". ?<br><br>7. In Measure M2, "Planning Authority" should be changed to "Planning Coordinator" in accordance with the latest functional model terminology. | | | | |
| | | R# | LOWER | MODERATE | HIGH | SEVERE |
| | | R1 | NA | \| Evidence that relay settings comply with the applicable criteria in R1.1 through 1.13 exists, but is incomplete or incorrect for one or more of the chosen criteria requirements. | NA | Relay settings do not comply with any of the requirements in R1.1 through R1.13 OR Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13. |
| | | R2 | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | NA | NA | NA |
| | | R3 | NA | Provided the list of facilities critical to the reliability of the | Provided the list of facilities critical to the reliability of the | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric |

| Entity | Segment | Comment | | | | |
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| | | | | Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | System; OR Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System; OR<br>Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |
| **Response:** The SDT acknowledges the comments (numbered for reference) and offers the following responses:<br>1. The presentation of VSLs in a table format appears to be a workable plan and the drafting team will re-format the VSLs so they are in a table when the standard is posted for its recirculation ballot.<br>2. The SDT agrees that the wording for Moderate VSL may be clarified. The standard has been revised as follows: “Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.”<br>3. The SDT points out that annual self-certification is one of several methods available for demonstrating compliance. The Compliance Enforcement Authority ultimately determines the appropriate method.<br>4. The reference document is a guide to aid understanding of the requirements in the standard. It imposes no requirements. The drafting team did replace the word “must” in item 2 of Appendix D with “should” to reflect that it is good industry practice.<br>5. The SDT did not use the capitalized form of the word, “critical” in this standard. The SDT deliberately avoided capitalizing the word, “critical” in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, “Critical Asset”. When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary.<br>6. The commenter is correct; the reference document is a guide to aid understanding of the requirements in the standard. It imposes no requirements.<br>**7.** The commenter is correct. “Planning Authority” has been changed to “Planning Coordinator.” Thank you. | | | | | | |
| Hydro One Networks, Inc. | 1, 3 | Hydro One Networks Inc. casts a negative vote on the PRC-023-1 “Transmission Relay Loadability” proposed standard. Although we support the concept and need for the standard and agree with the Requirements and Measures, we have serious concerns about its Applicability section. In support of our negative vote we offer the following comments: Section 4 (Applicability) indicates that the standard applies to every transmission line operated at 200 kV and above and to every transformer with low voltage terminals connected at 200 kV and above. In addition, it extends the applicability to transmission lines operated at 100 kV to 200 kV and to transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System. | | | | |

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| | | 1. The words used to define the applicability could lead to the standard extending beyond the Bulk Electric System facilities, which is contrary to the scope and applicability of NERC's purview. NERC does not currently have the authority to set a Standard to apply to every transmission facility operated at above 200 kV. Although NERC standards apply only to BES facilities, the language in the applicability section should be modified to a clear statement that leaves no room to interpretation regarding the facilities it applies to.<br><br>2. Planning Coordinators do not have the authority to and should not designate facilities operated between 100 kV and 200 kV as critical, unless these facilities are part of the Bulk Power System.<br><br>3. As currently drafted, the Standard is confusing as it might be read to suggest that everything over 200 kV is covered by the Standard and that a Planning Coordinator has the discretion to determine non-Bulk Power (or "Electric") System facilities as "Critical." Neither interpretation can be correct.<br><br>4. In an Informational Filing made on June 14, 2007, NERC submitted "regional definitions of "bulk electric system."<br>i. NERC explained on page 9 of that Filing that NPCC "identifies elements of the bulk-power system using an impact-based methodology, not a voltage based methodology."<br>ii. NPCC defines "bulk power system" to mean: "the interconnected electric systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area." In its June 14 filing, NERC confirmed that in the Northeast an "impact-based", not "voltage based" methodology would be used to define which facilities are part of the "bulk electric system." Therefore, in the Northeast not every transmission line operated above 200 kV is considered Bulk Power System and not every transformer with low voltage terminal connected at 200 kV is considered Bulk Power system. This is the case, because not every piece of equipment at that voltage has a "significant adverse impact outside of the local area." Rather, the language used in Applicability Sections 4.1.2 and 4.1.4( i.e., "critical to the reliability of the Bulk Electric System"( could be employed for classifying all transmission facilities( regardless of voltage.<br><br>5. NERC's Statement of Compliance Registry Criteria ("Registry Criteria"), which was approved by the Commission in Order No. 693, also supports the view that it is not appropriate to rely on a "bright-line" voltage cut-off for purposes of defining which Transmission Owners, Generation Owners and Distribution Providers are subject to the Standards. See NERC Registry Criteria III. (b), (c) & (d).<br>i. The NERC Registry Criteria applies to those Transmission Owners with assets defined as "Bulk Power System."<br>ii. The NERC Registry Criteria applies to those Generator Owners with assets of a certain size or that the Regional Entity deems "material to the reliability of the bulk power system." It is not based on voltage.<br>iii. The NERC Registry Criteria applies to those Distribution Providers that are directly connected to the "bulk power system" or are operated "for the protection of the bulk power system." It is not based on voltage. FERC endorsed the use of the Registry Criteria as a reasonable means "to ensure that the proper entities are registered and that each knows which Commission-approved Reliability Standard(s) are applicable to it." See Order 693 at P 689. Therefore, |

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| | | unless a Regional Entity registers an entity per the Registry Criteria, a Reliability Standard cannot be applicable to that entity. |
| **Response:** Comments 1, 2, 3, 4 and 5: The SDT acknowledges the commenter's point, and agrees that the standard applies only to the BES but it would not add clarity by specifying BES facilities as applicable since it is understood. Most stakeholders agreed with the applicability of the proposed standard – while the SDT acknowledges that the threshold may not be unanimously supported, it is an acceptable "starting point" for the application of this new set of requirements. If additional research is conducted that leads to a better threshold for identifying the facilities that should be applicable to the standard, then a new SAR can be developed to refine the applicability of the standard. At this point, the SDT believes that reliability is better protected by moving the standard forward with the proposed applicability – the intent of this set of requirements is to ensure that certain relays are set so they do not contribute to a cascading event such as the August 2003 disturbance.<br><br>NERC is working with the Regional Entities to refine the Compliance Registry to ensure that all entities that should be responsible for compliance with NERC Reliability Standards are identified and registered. | | |
| Hydro-Quebec TransEnergie | 1 | We (Hydro-Quebec-TransEnergie) reiterate our comment provided during the previous comment periods, where we asked that the Standard be clear on its applicability to the Bulk Power System (BPS). We still consider the Standard is unclear regarding this aspect. This Standard should apply only to the BPS. In NPCC, the BPS elements are determined through an impact based methodology, not a voltage based one. As written, the Standard is applicable to other elements than those of the BPS, at least for NPCC, because a voltage base is used (see 4.1.1 and 4.1.3). At the same time, the Standard seems to allow to be not applicable to a portion of the BPS (see 4.1.2, 4.1.4 and R3) where the BPS includes all elements at 100 kV level and above. In 4.1.2, 4.1.4 and R3, it is asked the Planning Coordinator to determine «critical element» to the reliability of the BES/BPS for voltage between 100 kV and 200 kV. We understand that the purpose of this action is to limit the applicability of the Standard in Region where no methodology is used to determine BPS elements. Are we talking here of «non critical» and «critical» BPS elements? Two types of BPS? |
| **Response:** The SDT acknowledges the commenter's point, and agrees that the standard applies only to the BES but it would not add clarity by specifying BES facilities as applicable since it is understood. Most stakeholders agreed with the applicability of the proposed standard – while the SDT acknowledges that the threshold may not be unanimously supported, it is an acceptable "starting point" for the application of this new set of requirements. If additional research is conducted that leads to a better threshold for identifying the facilities that should be applicable to the standard, then a new SAR can be developed to refine the applicability of the standard. At this point, the SDT believes that reliability is better protected by moving the standard forward with the proposed applicability – the intent of this set of requirements is to ensure that certain relays are set so they do not contribute to a cascading event such as the August 2003 disturbance.<br>. | | |
| Manitoba Hydro | 1 | Standard PRC-023-1 references requirements (R1.2, R1.3, R1.4, R1.7, R1.8, R1.9, R1.10, R1.11, and R1.13) to the application of a 15% relay margin above the circuit/equipment emergency rating. This 15% relay margin is arbitrary and does not consider the technology of the protective relaying equipment (i.e. electromechanical, solid state, microprocessor). For many relays, this margin is unnecessarily high and exposes the system to unnecessary risk. Rather, the relay margin should be based on the accuracy specifications of the protective relays in question. For many relays, this would reduce the relay margin while allowing for 100% of the equipment emergency rating. |

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| **Response:** The SDT asserts that the standard appropriately sets the minimum margin in the criteria to account for instrument transformer error, measurement error and relay accuracy. | | |
| Nebraska Public Power District | 1 | PRC-023 will require many utilities to increase load pick ups and reduce Zone 3 settings. Prior utility practice was to backup all remote substations and the next line terminals. With the approval of PRC-023 we will no longer be able to provide this remote backup. PRC-023 bases max loading on equipment ratings for transformers, line conductors, wavetraps, breakers, etc. Max loading should be based on worse-case load flows and not equipment ratings. In many situations, worse-case load flows will not be able to reach the equipment ratings rendoring the protection ineffective. If PRC-023 was based on worse-case load flows then current load pick ups and Zone 3 settings would be effective. PRC-023 was initially applied to EHV lines only. Then PRC-023 was changed to include 200KV lines and above. Then PRC-023 was changed to add SOTF, transformer loading, Out of Step, 100Kv-200Kv critical lines (with no clear critical criteria) and additional requirements. PRC-023 will continue to change and add additional burden to each utility, add costs, and reduce protection backup at substations. |
| **Response:** The purpose of PRC-023-1 is to ensure that protective relay systems will not limit transmission loadability. Requirements 1.3, 1.4, 1.7, 1.8, and 1.9 provide for the situations the commenter addresses. Maximum power transfer capability and maximum load flow can be used to determine the minimum relay loadability. The NERC SPCTF has published a technical report that is available on the NERC web site that provides guidance on ways to increase line relay loadability without compromising remote backup protection. | | |
| Sacramento Municipal Utility District | 1 | SMUD supports the draft standard but seeks the following improvements/clarifications:<br><br>Item 1: - R3 and D3.2 --> The Planning Coordinator is required to identify lines and transformer facilities in its area “Critical to the reliability of the Bulk Electric System”. This is a duplication of a similar requirement in the standard, CIP-002 (ftp://www.nerc.com/pub/sys/all_updl/standards/rs/CIP-002-1.pdf), on identification of “Critical Assets” (“Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets. ….(It includes any) assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.") Consider eliminating portions of the requirements that are being duplicated in PRC-023 and supplement in CIP-002 any additional requirements for determination of critical assets (eg: R3.1, R3.1.1 in PRC-023).<br><br>Item 2: D2.2 -- should be “with any one of the criteria in R1.1 through R1.13”. Also, as written, it appears to duplicate D2.4.2.<br><br>Item 3 Standard should clearly state that it is only applicable to transmission line relays at the generator terminal. If it is applicable to generator protection relays for generators connected to facilities defined in 4.1 through a step up transformer, then it should define the specific generator protection functions or relays it is applicable to, and the criteria that should be used for verification.<br><br>Item 4 5.1.1 describes the effective date. Since this is a new standard, additional time will be needed to perform relay settings calculations, documentation, verification, and implementation in the field (the |

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| | | documentation requirement for meeting NERC Blackout Recommendation #8a are presumed lower than those to meet a sanctionable standard). Recommend that the effective date be at least two quarters after approval by the NERC BOT. Thank you |
| **Response:** Item 1: In this instance the SDT did not use the capitalized form of the word, "critical" in this standard. The SDT deliberately avoided capitalizing the word, "critical" in PRC-023-1 to avoid confusing in Requirement R3 PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, "Critical Asset". When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary.<br><br>Item 2: The SDT agrees that the suggested wording for Moderate VSL may be clarified. The standard has been revised accordingly as follows: "Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the sub requirements." 2.2 address incomplete or incorrect evidence where 2.4.2 addresses missing evidence.<br><br>Item 3: Clause 4.2 in the Applicability section specifically refers to the "facilities defined in 4.1.1 through 4.1.4". The SDT asserts that this specifically addresses your comment.<br><br>Item 4: The SDT asserts that the first calendar quarter following applicable regulatory approval (as opposed to BOT approval) affords adequate lead time for achieving compliance with this standard. This standard codifies the technical work that was directed throughout industry by the NERC Planning Committee. This work was directed to be complete by the middle of 2008 with the exception of approved requests for delayed implementation. Therefore entities should already be compliant with this standard. | | |
| SaskPower | 1 | 1. The following are SaskPower's and the Saskatchewan regulatory Jurisdiction's comments. SaskPower and the Saskatchewan Regulatory Jurisdiction believe that this standard is too prescriptive and that there is a forced assumption of risk. The amount of risk that Saskatchewan is willing to assume is a business/reliability decision that can only be determined from an internal risk analysis. SaskPower and the Saskatchewan Regulatory Jurisdiction do not agree with the prescriptive nature of the standard that protection systems are designed only to remove faults but not to prevent equipment damage, and that operator action is required to protect facilities from overload conditions. This is not how the Saskatchewan system was/is planned, designed, and operated. SaskPower and the Saskatchewan Regulatory Jurisdiction believe that protection systems provide last resort protection to prevent equipment damage when operators do not have sufficient time or fail to correctly respond to overload conditions. Saskatchewan has always used sound engineering judgment as to how much operators are allowed to do versus allowing our protection systems to fail-safe the system. We carefully balance the risk of a having a system outage versus the benefit of having our system fail-safe so that there is no equipment damage and the system can be restored.<br><br>2. Effective Dates: SaskPower and the Saskatchewan Regulatory Jurisdiction understand that the proposed effective dates were revised based on FERC staff comments to reflect that in some jurisdictions, the approval of a standard is tied to BOT adoption and not a separate regulatory approval. The Saskatchewan Regulatory Jurisdiction disagrees with this approach. Regulatory approval or how it is done is an internal Saskatchewan |

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| | | matter that is outside the NERC standards process and the Saskatchewan Regulatory Jurisdiction will inform NERC when standards are effective in Saskatchewan. Recommend using the generic form language of "after applicable regulatory approval".<br><br>3. SaskPower and the Saskatchewan Regulatory Jurisdiction believe that this standard should only apply to the BPS as determined by the Planning Coordinator's specific impact based methodology. There are many instances where 200kV and higher transmission lines do not constitute a BPS facility and the only lines that should be considered are BPS lines determined from an impact based methodology. Presently the standard only has an implicit impact based determined BPS in the 100-200kV class. Recommend changing the applicability to 100kV and above as determined by the Planning Coordinator.<br><br>4. SaskPower and the Saskatchewan Regulatory Jurisdiction believe that the margins listed in the standard should be set by the PC and the TO, otherwise include detailed rationales/justification for their use. The standard should only provide a list of issues to consider in setting the margin, such as done with TRM in the ATC standards.<br><br>5. R1.1 and R1.10: SaskPower and the Saskatchewan Regulatory Jurisdiction believe that these requirements effectively set the Emergency Rating of the facility, as the standard implies operation up to that level. This conflicts with the FAC standards. SaskPower and the Saskatchewan Regulatory Jurisdiction disagree with this approach.<br><br>6. Note 1: SaskPower and the Saskatchewan Regulatory Jurisdiction question why this is part of the standard. This should be removed as it refers to a NERC administrative/compliance process outside the standards process. If it is kept how will it be removed when it finishes? A SAR?<br><br>7. R1.6: SaskPower and the Saskatchewan Regulatory Jurisdiction are familiar with the IEEE paper that the margin is based on, but the paper doesn't explain the basis.<br><br>8. R1.7 to 1.9: SaskPower and the Saskatchewan Regulatory Jurisdiction believe that the use of "any system configuration" is too simplistic and onerous. The language should be changed to something like "any practical configuration as determined by the PC". "Any configuration" is not practical or justified from a operational or planning perspective.<br><br>9. R1.11: SaskPower and the Saskatchewan Regulatory Jurisdiction do not agree with this approach as the Saskatchewan system does not use the standard mandated top oil or winding temperature values. The applicable IEEE standard states what transformers are/were supposed to be designed to under that standard. It does not recommend or mandate operation there. This decision is left up to the equipment owner. This is an equipment capability issue that must be left to the TO and PC. |

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| | | 10. Section D: SaskPower and the Saskatchewan Regulatory Jurisdiction believe that Compliance Monitor is a more appropriate term than Compliance Enforcement Authority.<br><br>11. Attachment A Note 2: SaskPower and the Saskatchewan Regulatory Jurisdiction question its inclusion in the standard as it does not seem directly related to relay loadability. |

**Response:**

1. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond. NERC Standards TOP-001 through TOP-004 require transmission operators to respond to overloaded facilities. In addition, the amount of risk an individual entity is willing to take must be within the boundaries set to establish a level of reliability needed to preserve the integrity of the interconnected bulk electric system.
2. The language in the proposed effective date section of the standard was developed to accommodate the varying methods of approving reliability standards that currently exist throughout North America.
   Most stakeholders agreed with the applicability of the proposed standard – while the SDT acknowledges that the threshold may not be unanimously supported, it is an acceptable "starting point" for the application of this new set of requirements. If additional research is conducted that leads to a better threshold for identifying the facilities that should be applicable to the standard, then a new SAR can be developed to refine the applicability of the standard. At this point, the SDT believes that reliability is better protected by moving the standard forward with the proposed applicability – the intent of this set of requirements is to ensure that certain relays are set so they do not contribute to a cascading event such as the August 2003 disturbance.
3. The SDT asserts that the standard appropriately sets the minimum margin in the criteria to account for instrument transformer error, measurement error and relay accuracy.
4. On the contrary, this standard requires that relays be set above the pre-determined emergency Facility Ratings. Only in the case where relays cannot adequately protect the facility if set above the Facility Rating, does this standard require that the Facility Rating be changed to accommodate the relay settings (R1.12.3).
5. Pre-approved temporary exceptions had to be accommodated. Once they have all been mitigated, the note will have no effect on the standard. It can be removed any time after that by any appropriate means.
6. The SDT assumes the commenter is referring to the paper cited in the Reference Document. This criterion is taken from IEEE C37.102 Generator Protection Guide which references ANSI C50.13-2005 as well as other citations shown in the Reference Document.
7. R1.7 through R1.9 are intended to allow planning entities to use engineering studies to determine the maximum load flow through a facility. The SDT developed these requirements to provide sufficient flexibility for determining minimum relay settings.
8. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond. NERC Standards TOP-001 through TOP-004 require transmission operators to respond to overloaded facilities.
9. The Uniform Compliance and Monitoring Program section 3.0 defines the entity Compliance Enforcement Authority in its documentation. The use here is consistent with that document.
10. Attachment A Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent

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| | | tripping for true faults during extreme loading conditions. |
| Sierra Pacific Power Co. | 1 | I am voting affirmative; however, there are still several problems with this Standard. It refers to the entity Planning Coordinator, which does not exist in the NERC registry.<br><br>Second, it specifies that this entity is to determine which facilities constitute BES when this could conflict with the BES determination made by the Region and its RC's. However, these issues were not large enough to warrant a negative vote. They nonetheless need more attention in the implementation of this Standard. |
| **Response:**<br>1. Planning Coordinator is a defined function in the NERC Reliability Functional Model, Version 3, approved by the BOT Feb. 13, 2007. In a filing to FERC, NERC clarified that the intent of the Planning Authority and the Planning Coordinator “functions” is the same, and in an Order, FERC accepted NERC’s position on these two “functions.”<br><br>**2.** The SDT acknowledges the commenter’s point. In the cases where the PC identifies critical facilities that are in conflict with the definition of BES, the applicability will be limited to those facilities that are part of the BES. The standard does not specify that the PC determine which facilities constitute BES. | | |
| Xcel Energy, Inc. | 1, 3, 6 | (1) Xcel Energy believes that Generator Owners and Distribution Providers should be removed from the Applicability list. If an entity that owns generation or distribution facilities also owns transmission facilities at a voltage level of 100 kV or higher as listed in Section 4.1, then by definition that entity is a Transmission Owner.<br><br>(2) Xcel Energy is concerned that this standard could be interpreted as prohibiting use of out-of-step blocking elements associated with reset timers that allow tripping after time delays. In some cases, prohibition of these types of devices could increase rather than decrease the risk of cascading outages. On very long transmission lines that are subject to power swings, Xcel Energy uses out-of-step relays associated with timing devices to allow the system to adjust to power swings that are not associated with a system disturbance. Absent use of such delayed trip blocking systems, major transmission lines could be improperly forced out of service if relays trip in response to a power swing.<br><br>The specific issue of concern to Xcel Energy arises in the language in item 2 of Attachment A, which states that the "standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements."<br><br>This statement could be interpreted as prohibiting use of any type of blocking system that operates within the defined loading conditions. While Xcel Energy agrees that use of simple blocking systems may be inappropriate, blocking systems associated with reset timers are not necessarily fraught with the same issues. Use of reset timers along with a blocking system can allow the system sufficient time (two to four seconds) to adjust to a power swing that might look to a relay like a system disturbance. Disabling such relays at a line terminal could result in it tripping during a stable, recoverable swing condition, which would over-load adjacent lines, and could contribute to a |

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| | | cascading outage, which is what NERC Standard PRC-023-1 is intended to prevent. To address this issue, out of step relays with override timers should be excluded from the application of the standard. |

**Response:**
1. Generator Owners and Distribution Providers were included in the Applicability section because they may own relevant facilities as defined in 4.1.1 through 4.1.4.
2. Attachment A Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults during extreme loading conditions. For the conditions you cite, more complex out-of-step blocking schemes may be needed.

| Entity | Segment | Comment |
|---|---|---|
| California ISO | 2 | The purpose of this Standard is to attempt to minimize the probability of cascading outages due to relay action, where the relays were set to operate on phase load currents at levels below Transmission Facility emergency ratings. The Standard has an Attachment A which identifies relay types and / or systems that are subject to this proposed Standard. Attachment A includes typical pilot schemes, i.e. POTT (Permissive Overreaching Transfer Trip), PUTT (Permissive Under Reaching Transfer Trip), DCB (Direction Comparison Blocking) and DCUB (Directional Comparison Unblocking). In general, these pilot schemes will normally not operate only on high load current. Yet the Standard specifically identifies phase distance and over current relays in these schemes. From this, it can be implied that the Standard does not want any of these pilot schemes to arm under high load conditions. The pilot scheme, though, should not misoperate for this condition unless the communications system fails. If this is the concern here, in the CAISO opinion the Standard should be more explicit, and clearly state this concern. There is an exception to the above discussion. In some cases, the relay elements in pilot schemes may operate independent of communications. As an example, the phase distance element in a POTT scheme may be designed to trip in a time delayed fashion if it remains picked up for a pre-determined length of time. It this is the item of concern, the CAISO suggests that the Standard wording be modified. One possibility would be to reword Paragraph 1.5 in Attachment A to state: "1.5 Phase distance and over current relays in communications aided protection schemes, which serve as back up relays and trip independent of pilot communications, including but not limited to: " Also, this proposed Standard is most unusual in that it contains planning criteria and also action (and severity levels) for the Planning Coordinator. The term Planning Coordinator is not defined in the Standard. |

**Response:**
1. The pilot schemes referenced in the comment are susceptible to operation during extreme loading conditions absent communication failure and must comply with this standard. Such operations have been documented by previous disturbance analysis.
2. Planning Coordinator is a defined function in the NERC Reliability Functional Model, Version 3, approved by the BOT Feb. 13, 2007.

| Entity | Segment | Comment |
|---|---|---|
| ISO New England, Inc. | 2 | ISO New England submits an affirmative ballot with the understanding that irrespective of voltage levels in the standard, FERC stated that the voltages levels specified are only applicable to the BPS, not beyond, per the legislation. |

**Response:** The SDT acknowledges the commenter's point, and agrees that the standard applies only to the BES.

| Entity | Segment | Comment |
|---|---|---|
| Midwest ISO, Inc. | 2 | While we are voting for this standard, there are some issues that should still be addressed. There should be clarity on whether the critical facility list is somehow different than other critical facility lists in the standards.<br><br>Some of our stakeholders have concerns about the relay settings required in 1.10 and 1.11 for transformers. |
| **Response:** In this instance, the SDT did not use the capitalized form of the word, "critical" in this standard. The SDT deliberately avoided capitalizing the word, "critical" in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, "Critical Asset". When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary.<br>With respect to transformers, the SDT cannot provide a specific response absent detailed concerns to which to respond. | | |
| New Brunswick System Operator | 2 | Although NBSO agrees with the technical aspects of this proposed Standard the reason for the Negative vote is Standard's applicability. NBSO believes this proposed Standard, as well as all NERC Standards, should apply to all BPS elements. NBSO further believes that the issue is really caused by the multiple definitions of the BPS. The uncertainty around BPS issue has lingered on too long and needs to be resolved. NBSO further believes the BPS should be defined with an impact based methodology and not by selecting an arbitrary voltage level. |
| **Response:** Most stakeholders agreed with the applicability of the proposed standard – while the SDT acknowledges that the voltage threshold may not be unanimously supported, it is an acceptable "starting point" for the application of this new set of requirements. If additional research is conducted that leads to a better threshold for identifying the facilities that should be applicable to the standard, then a new SAR can be developed to refine the applicability of the standard. At this point, the SDT believes that reliability is better protected by moving the standard forward with the proposed applicability – the intent of this set of requirements is to ensure that certain relays are set so they do not contribute to a cascading event such as the August 2003 disturbance. | | |
| Bonneville Power Administration | 3 | While we agree with the intent of this standard, we believe it is more conservative than necessary to meet the goal of preventing a relay action to trip a line under non-fault loading. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| FirstEnergy Solutions | 3 | FirstEnergy Corp. (FE) appreciates the hard work put forth by NERC's Relay Loadability Standard Drafting Team. However, at this time, FE is voting NO to the standard as written and asks that NERC consider our following questions, comments, and suggestions. Issues<br><br>1. We do not agree with the Violation Severity Levels (VSL) as written. First, we believe the VSLs should be reformatted to match the table format as presented in the NUC-001 and ATC/TTC standards that are presently out for comment. The Relay Loadability team has grouped the VSLs inconsistent with the NUC and ATC standard and we firmly believe that the table format is a much better method of mapping the VSLs with the requirements.<br>2. Also, we propose modified wording for the Moderate VSL for R1 in an effort to make the VSL clearer. We have included a proposed table format and red-line on Pg. 2 of these comments. |

| Entity | Segment | Comment |
|---|---|---|
| | | 3. Regarding Part D, Sec. 1.4 (Additional Compliance Information), we do not agree with the requirement for annual self-certification because it only creates more work for the entities and does not add value to monitoring of reliability. Relay loadability schemes do not change enough to warrant annual certification. We suggest changing the required self-certification to every two years.<br><br>4. Page X in Appendix D of the Reference Document seems to mandate a 75% voltage limit for SOTF supervision for newer protection schemes. This reference is under point #2 in the section titled SOTF line loadability considerations. This requirement is not present in the proposed standard and we believe it should not be present in the Reference Document. We propose eliminating the second sentence from point #2 in that section of the Reference Document.<br><br>5. There are several references to "critical" facilities in the standard. It is not clear what criteria would be used to determine a "critical" facility in the context of requirements related to relay settings. We believe this term should be modified and should be limited to the CIP standards and not used in this standard. Other Comments/Suggestions<br><br>6. Per Part F of the standard regarding the PRC-023 Reference Document "Determination and Application of Practical Relaying Loadability Ratings", it is FE's interpretation that this document is strictly a "guide" for use in helping understand how to calculate this data and not enforceable and mandatory, correct? Our interpretation aligns with NERC's Reliability Standards Development Procedure Version 6.1, on pg.9 under "Supporting References" which states that Standard supplements "are not themselves mandatory".<br><br>7. In Measure M2, "Planning Authority" should be changed to "Planning Coordinator" in accordance with the latest functional model terminology. Sincerely, FirstEnergy Corp. FERC Compliance Group Akron, OH |

**Response:** The SDT acknowledges the comments (numbered for reference) and offers the following responses:

1. The presentation of VSLs in a table format appears to be a workable plan and the drafting team will re-format the VSLs so they are in a table when the standard is posted for its recirculation ballot
2. The SDT agrees that the wording for Moderate VSL was not as clear as desired. . The standard has been revised as follows: "Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the sub requirements."
3. The SDT points out that annual self-certification is one of several methods available for demonstrating compliance. The Compliance Enforcement Authority ultimately determines the appropriate method.
4. The reference document is a guide to aid understanding of the requirements in the standard. It imposes no requirements. The word "must" in item 2 of Appendix D was replaced with "should" to reflect that it is good industry practice.
5. In this instance the SDT did not use the capitalized form of the word, "critical" in this standard. The SDT deliberately avoided capitalizing the word, "critical" in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, "Critical Asset". When a word is not capitalized, the

| Entity | Segment | Comment |
|---|---|---|
| word has the same meaning as that found in any collegiate dictionary.<br>6. The commenter is correct; the reference document is a guide to aid understanding of the requirements in the standard. It imposes no additional requirements beyond the standard itself.<br>**7.** The commenter is correct. “Planning Authority” has been changed to “Planning Coordinator.” Thank you. | | |
| Kissimmee Utility Authority | 3 | While this standard is necessary for the future loadability setting sfor the system relays there are a couple of areas in the text that are stil confusing as to what is being required. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| North Carolina Municipal Power Agency #1 | 4 | I believe this standard needs further clarification exempting equipment that does not have a material impact on the BES. The current language in this standard is too vague regarding this issue. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| Wisconsin Energy Corp. | 4 | The word "critical" should be removed from Requirement 3 because of the confusion it will create with other existing standards. The removal of this word will not impact that substance of the requirement but will clarify that any list developed by the PC only applies to PRC-023.<br><br>We Energies offers the following modification: "The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area should be subject to Requirement 1 and 2 in order to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability." |
| **Response:** The SDT thanks the commenter for the offered revision. In this instance the SDT did not use the capitalized form of the word, “critical” in this standard. The SDT deliberately avoided capitalizing the word, “critical” in PRC-023-1 to avoid confusing Requirement R3 in PRC-023 with requirements in the Critical Infrastructure Protection series of standards that do use the NERC-defined term, “Critical Asset”. When a word is not capitalized, the word has the same meaning as that found in any collegiate dictionary. | | |
| Bonneville Power Administration | 5 | While we agree with the intent of this standard, we believe it is more conservative than necessary in order to meet the goal of preventing a relay action to trip a line under non-fault loading. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| City of Tallahassee | 5 | I still feel that this standard is over and above the needs of the BES. However, based on comments submitted, the "industry concesus" appears to be that this needs to happen. The additional expense incurred will provide very little additional benefit to transmission owners and users. |
| **Response:** Thank you for your comment. In addition to industry consensus, analysis of actual disturbances warrants that this standard is needed because relay loadability has historically contributed to system disturbances. | | |

| Entity | Segment | Comment |
|---|---|---|
| Constellation Generation Group | 5 | When read 4.4.2 of the proposed standard about applicability to generation and then refer to Appendix A in 3.3.4, it is very confusing as conditions as to which generation should be included or exclused from this new Standard. |
| **Response:** GOs are included in the Applicability section because they may own relevant facilities as defined in 4.1.1 through 4.1.4.<br><br>Appendix A section 3.4 excludes generator protective relays susceptible to load from the requirements of this standard. These relays and other generation protective relays that are responsive to system conditions are under consideration in a separate standard. | | |
| Xcel Energy, Inc. | 5 | I am concerned that this standard as drafted would limit the application of out of step block trip functions for remotely-connected systems. |
| **Response:** Attachment A, Item 2 is intended to ensure that facilities are adequately protected for faults. Out-of-step blocking elements may prevent tripping for true faults during extreme loading conditions. For conditions involving remotely-connected systems, more complex out-of-step blocking schemes may be needed. | | |
| Bonneville Power Administration | 6 | While we agree with the intent of this standard, we believe it is more conservative than necessary in order to meet the goal of preventing a relay action to trip a line under non-fault loading. |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| JDRJC Associates | 8 | More work needs to be done on Violation Severity Limits |
| **Response:** The SDT acknowledges the comment, but cannot provide a specific response absent detailed concerns. | | |
| Midwest Reliability Organization | 10 | MRO is not a user, owner or operator and the risk lies with the individual entities. Assignment of VSL of moderate in section 3 of the compliance for planning coordinators being late with the critical facilities list should be lower |
| **Response:** The SDT acknowledges the comment. The VSL is assigned according to the Violation Severity Level Development Guideline document that is found on the NERC web site. VSLs are not related to ‘importance’ or ‘reliability-related risk’ – rather VSLs are used to break down non-compliance into various levels to describe a range of performance from the level where an entity is mostly compliant (Lower VSL) to a level where the entity missed most or all of the requirement (Severe VSL). | | |

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| 2. First ballot of standards. | |
| 3. Recirculation ballot of standards. | |
| 4. 30-day posting before board adoption. | |
| 5. Board adopts standards. | To be determined |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   **4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

   **4.1.1** Transmission lines operated at 200 kV and above.

   **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

   **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

   **4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

   **4.4.** Planning Coordinators.

5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2:

   **5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

   **5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   **5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

   **5.2.** Requirement 3: 18 months following applicable regulatory approvals.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Compliance Enforcement Authority

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

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| 5. Board adopts standards. | To be determined |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   **4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

   **4.1.1** Transmission lines operated at 200 kV and above.

   **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

   **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

   **4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

   **4.4.** Planning Coordinators.

5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2:

   **5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — ~~January 1, 2008 or~~ the beginning of the first calendar quarter following applicable regulatory approvals~~, whichever is later~~.

   **5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   **5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

   **5.2.** Requirement 3: 18 months following applicable regulatory approvals.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning ~~Authority~~Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

### 1.1. Compliance Monitoring Responsibility

**1.1.1** Compliance Enforcement Authority

### 1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

### 1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements ~~in~~ R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

**1.1.** Phase distance.

**1.2.** Out-of-step tripping.

**1.3.** Switch-on-to-fault.

**1.4.** Overcurrent relays.

**1.5.** Communications aided protection schemes including but not limited to:

**1.5.1** Permissive overreach transfer trip (POTT).

**1.5.2** Permissive under-reach transfer trip (PUTT).

**1.5.3** Directional comparison blocking (DCB).

**1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

**3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications.

**3.2.** Protection systems intended for the detection of ground fault conditions.

**3.3.** Protection systems intended for protection during stable power swings.

**3.4.** Generator protection relays that are susceptible to load.

**3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

**3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.

**3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

**3.8.** Relay elements associated with DC lines.

**3.9.** Relay elements associated with DC converter transformers.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

**Maureen E. Long**
Standards Process Manager

January 31, 2007

## Re: Recirculation Ballot Window Opens

**The Standards Committee announces the following standards action:**

### Recirculation Ballot Window for PRC-023-1 — Transmission Relay Loadability is Open

The recirculation ballot for the PRC-023-1 — Transmission Relay Loadability is open through 8 p.m. (EST) on Saturday, February 9, 2008.

This standard addresses the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called "zone 3 relay" issue, expanded to address other protection devices subject to unintended operation during extreme system conditions. The proposed standard establishes minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

The ballot for this standard also includes the Relay Loadability Implementation Plan.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of initial ballot comments. The drafting team made some minor edits to the standard following the initial ballot and has posted both a clean and a redline version of the standard. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

# Standards Announcement

## Initial Ballot Results for Nine Sets of Violation Severity Levels

The initial ballot for each of the nine sets of Violation Severity Levels in Project 2007-23 was conducted from January 21 through January 28, 2008. Through an administrative error, the results were posted on the Ballot Results standards web page, but were not formally announced.

| Initial Ballot Results | | |
|---|---|---|
| **Title** | **Quorum** | **Approval** |
| VSLs - BAL | 94.29% | 69.55% |
| VSLs – CIP, COM, VAR | 94.81% | 74.05% |
| VSLs – EOP | 94.76% | 62.07% |
| VSLs – FAC, MOD | 94.74% | 68.17% |
| VSLs – INT, PER NUC | 94.53% | 74.17% |
| VSLs – IRO | 94.79% | 75.70% |
| VSLs – PRC | 94.31% | 71.01% |
| VSLs – TOP | 94.79% | 77.10% |
| VSLs – TPL | 94.71% | 64.96% |

Balloters submitted many comments with specific suggestions for improvements to many of the VSLs. In the interest of developing the best set of VSLs practical (given the March 1, 2008 deadline), the Standards Committee authorized the VSL DT to consider stakeholder comments from the initial VSL ballots and make improvements to the proposed VSLs before proceeding with the recirculation ballot, and the VSL DT has done that.

The VSL DT posted its consideration of the comments submitted with the initial ballots and **revised VSLs**. The nine recirculation ballots are open through 8 p.m. on Tuesday, February 19, 2008.

### Recirculation Ballot Results for Transmission Relay Loadability Standard

The recirculation ballot for PRC-023-1 — Transmission Relay Loadability was conducted from January 31 through February 9, 2008 and the ballot passed.

Quorum: 93.27 %
Approval: 82.64 %

This standard addresses the cascading transmission outages that occurred in the August 2003 blackout when backup distance and phase relays operated on high loading and low voltage without electrical faults on the protected lines. This is the so-called 'zone 3 relay' issue, expanded to address other protection devices subject to unintended operation during extreme system conditions. The standard establishes minimum loadability criteria for these relays to minimize the chance of unnecessary line trips during a major system disturbance.

### Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

*For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.*

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**Reliability Standards**



| Ballot Results | |
|---|---|
| **Ballot Name:** | Standard PRC-023-1 - Transmission Relay Loadability_rc |
| **Ballot Period:** | 1/31/2008 - 2/9/2008 |
| **Ballot Type:** | recirculation |
| **Total # Votes:** | 194 |
| **Total Ballot Pool:** | 208 |
| **Quorum:** | **93.27 % The Quorum has been reached** |
| **Weighted Segment Vote:** | 82.64 % |
| **Ballot Results:** | **The Standard has Passed** |

**Summary of Ballot Results**

| Segment | Ballot Pool | Segment Weight | Affirmative # Votes | Affirmative Fraction | Negative # Votes | Negative Fraction | Abstain # Votes | No Vote |
|---|---|---|---|---|---|---|---|---|
| 1 - Segment 1. | 68 | 1 | 47 | 0.758 | 15 | 0.242 | 2 | 4 |
| 2 - Segment 2. | 10 | 0.8 | 6 | 0.6 | 2 | 0.2 | 1 | 1 |
| 3 - Segment 3. | 52 | 1 | 37 | 0.86 | 6 | 0.14 | 4 | 5 |
| 4 - Segment 4. | 10 | 0.9 | 7 | 0.7 | 2 | 0.2 | 0 | 1 |
| 5 - Segment 5. | 29 | 1 | 19 | 0.76 | 6 | 0.24 | 2 | 2 |
| 6 - Segment 6. | 20 | 1 | 14 | 0.737 | 5 | 0.263 | 1 | 0 |
| 7 - Segment 7. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 8 - Segment 8. | 1 | 0.1 | 1 | 0.1 | 0 | 0 | 0 | 0 |
| 9 - Segment 9. | 10 | 0.9 | 9 | 0.9 | 0 | 0 | 0 | 1 |
| 10 - Segment 10. | 7 | 0.6 | 6 | 0.6 | 0 | 0 | 1 | 0 |
| **Totals** | **208** | **7.4** | **147** | **6.115** | **36** | **1.285** | **11** | **14** |

**Individual Ballot Pool Results**

| Segment | Organization | Member | Ballot | Comments |
|---|---|---|---|---|
| 1 | AEP Service Corp. -- Transmission System AEP | Scott P. Moore | Affirmative | |
| 1 | Allegheny Power | Rodney Phillips | Affirmative | |
| 1 | Alliant Energy | Kenneth Goldsmith | Affirmative | |
| 1 | AltaLink Management Ltd. | Rick Spyker | Affirmative | |
| 1 | American Public Power Association | E. Nick Henery | | |
| 1 | American Transmission Company, LLC | Jason Shaver | Negative | View |
| 1 | Arizona Public Service Co. | Cary B. Deise | Affirmative | |
| 1 | Associated Electric Cooperative, Inc. | John Bussman | Affirmative | |
| 1 | Avista Corp. | Scott Kinney | Affirmative | |
| 1 | Bonneville Power Administration | Donald S. Watkins | Negative | View |

| | | | | |
|---|---|---|---|---|
| 1 | CenterPoint Energy | Paul Rocha | Negative | View |
| 1 | Central Maine Power Company | David Mark Conroy | | |
| 1 | Consolidated Edison Co. of New York | Edwin E. Thompson PE | Affirmative | |
| 1 | Dairyland Power Coop. | Robert W. Roddy | Affirmative | |
| 1 | Dominion Virginia Power | William L. Thompson | Affirmative | |
| 1 | Duke Energy Carolina | Douglas E. Hils | Affirmative | |
| 1 | East Kentucky Power Coop. | George S. Carruba | Affirmative | |
| 1 | El Paso Electric Company | Dennis Malone | Abstain | |
| 1 | Entergy Corporation | George R. Bartlett | Affirmative | |
| 1 | Exelon Energy | John J. Blazekovich | Affirmative | |
| 1 | FirstEnergy Energy Delivery | Robert Martinko | Affirmative | |
| 1 | Florida Keys Electric Cooperative Assoc. | Dennis Minton | Negative | |
| 1 | Florida Power & Light Co. | C. Martin Mennes | Affirmative | |
| 1 | Gainesville Regional Utilities | Luther E. Fair | Affirmative | |
| 1 | Great River Energy | Gordon Pietsch | Negative | |
| 1 | Hoosier Energy Rural Electric Cooperative, Inc. | Damon Holladay | Affirmative | |
| 1 | Hydro One Networks, Inc. | Ajay Garg | Negative | View |
| 1 | Hydro-Quebec TransEnergie | Julien Gagnon | Negative | View |
| 1 | Idaho Power Company | Ronald D. Schellberg | Affirmative | |
| 1 | ITC Transmission | Brian F. Thumm | | |
| 1 | JEA | Ted E. Hobson | Affirmative | |
| 1 | Kansas City Power & Light Co. | Jim Useldinger | Affirmative | |
| 1 | Keyspan LIPA | Richard J. Bolbrock | Affirmative | |
| 1 | Lakeland Electric | Larry E Watt | Affirmative | |
| 1 | Lincoln Electric System | Doug Bantam | Affirmative | |
| 1 | Lower Colorado River Authority | Martyn Turner | Affirmative | |
| 1 | Manitoba Hydro | Robert G. Coish | Negative | View |
| 1 | Minnesota Power, Inc. | Carol Gerou | Affirmative | |
| 1 | Municipal Electric Authority of Georgia | Jerry J Tang | Affirmative | |
| 1 | National Grid | Michael J Ranalli | Affirmative | |
| 1 | Nebraska Public Power District | Richard L. Koch | Negative | View |
| 1 | New Brunswick Power Transmission Corporation | Wayne N. Snowdon | Affirmative | |
| 1 | New York Power Authority | Ralph Rufrano | Affirmative | |
| 1 | Northeast Utilities | David H. Boguslawski | Affirmative | |
| 1 | Northern Indiana Public Service Co. | Joseph Dobes | Negative | |
| 1 | Oklahoma Gas and Electric Co. | Melvin H. Perkins | Affirmative | |
| 1 | Oncor Electric Delivery | Charles W. Jenkins | Affirmative | |
| 1 | Otter Tail Power Company | Lawrence R. Larson | Affirmative | |
| 1 | Pacific Gas and Electric Company | Chifong L. Thomas | Negative | |
| 1 | PacifiCorp | Robert Williams | Affirmative | |
| 1 | Potomac Electric Power Co. | Richard J. Kafka | Affirmative | |
| 1 | PP&L, Inc. | Ray Mammarella | Affirmative | |
| 1 | Progress Energy Carolinas | Sammy Roberts | Affirmative | |
| 1 | Sacramento Municipal Utility District | Dilip Mahendra | Negative | View |
| 1 | Salt River Project | Robert Kondziolka | Affirmative | |
| 1 | Santee Cooper | Terry L. Blackwell | Affirmative | |
| 1 | SaskPower | Wayne Guttormson | Negative | View |
| 1 | Seattle City Light | Christopher M. Turner | Affirmative | |
| 1 | Sierra Pacific Power Co. | Richard Salgo | Affirmative | View |
| 1 | Southern California Edison Co. | Dana Cabbell | Abstain | |
| 1 | Southern Company Services, Inc. | Horace Stephen Williamson | Affirmative | |
| 1 | Southwestern Power Administration | Mike Wech | Negative | |

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|---|---|---|---|---|
| 1 | Texas Municipal Power Agency | Frank J. Owens | Affirmative | |
| 1 | Tri-State G & T Association Inc. | Bruce A Sembrick | Affirmative | |
| 1 | Tucson Electric Power Co. | Ronald P. Belval | Affirmative | |
| 1 | Westar Energy | Allen Klassen | | |
| 1 | Western Area Power Administration | Robert Temple | Affirmative | |
| 1 | Xcel Energy, Inc. | Gregory L. Pieper | Negative | View |
| 2 | Alberta Electric System Operator | Anita Lee | Affirmative | |
| 2 | British Columbia Transmission Corporation | Phil Park | Affirmative | |
| 2 | California ISO | David Hawkins | Negative | View |
| 2 | Electric Reliability Council of Texas, Inc. | Roy D. McCoy | Abstain | |
| 2 | Independent Electricity System Operator | Don Tench | Affirmative | |
| 2 | ISO New England, Inc. | Kathleen Goodman | Affirmative | View |
| 2 | Midwest ISO, Inc. | Terry Bilke | Affirmative | View |
| 2 | New Brunswick System Operator | Alden Briggs | Negative | View |
| 2 | New York Independent System Operator | Gregory Campoli | | |
| 2 | PJM Interconnection, L.L.C. | Tom Bowe | Affirmative | |
| 3 | Alabama Power Company | Robin Hurst | Affirmative | |
| 3 | Allegheny Power | Bob Reeping | Affirmative | |
| 3 | American Electric Power | Raj Rana | Affirmative | |
| 3 | Arizona Public Service Co. | Thomas R. Glock | Affirmative | |
| 3 | Atlantic City Electric Company | James V. Petrella | Affirmative | |
| 3 | Avista Corp. | Robert Lafferty | Affirmative | |
| 3 | BC Hydro and Power Authority | Pat G. Harrington | Abstain | |
| 3 | Bonneville Power Administration | Rebecca Berdahl | Negative | View |
| 3 | City of Tallahassee | Rusty S. Foster | Affirmative | |
| 3 | City Public Service of San Antonio | Edwin Les Barrow | Affirmative | |
| 3 | Consumers Energy Co. | David A. Lapinski | Affirmative | |
| 3 | Delmarva Power & Light Co. | Michael R. Mayer | Affirmative | |
| 3 | Dominion Resources, Inc. | Jalal (John) Babik | Affirmative | |
| 3 | Duke Energy Carolina | Henry Ernst-Jr | Affirmative | |
| 3 | Entergy Services, Inc. | Matt Wolf | Negative | |
| 3 | Farmington Electric Utility System | Alan Glazner | Affirmative | |
| 3 | FirstEnergy Solutions | Joanne Kathleen Borrell | Affirmative | |
| 3 | Florida Municipal Power Agency | Michael Alexander | Affirmative | |
| 3 | Florida Power & Light Co. | W.R. Schoneck | Affirmative | |
| 3 | Florida Power Corporation | Lee Schuster | Abstain | |
| 3 | Georgia Power Company | Leslie Sibert | Affirmative | |
| 3 | Great River Energy | Sam Kokkinen | Negative | |
| 3 | Gulf Power Company | Gwen S Frazier | Affirmative | |
| 3 | Hydro One Networks, Inc. | Michael D. Penstone | Negative | View |
| 3 | JEA | Garry Baker | Affirmative | |
| 3 | Kissimmee Utility Authority | Gregory David Woessner | Affirmative | View |
| 3 | Lincoln Electric System | Bruce Merrill | Affirmative | |
| 3 | Louisville Gas and Electric Co. | Charles A. Freibert | | |
| 3 | Manitoba Hydro | Ronald Dacombe | Negative | |
| 3 | MidAmerican Energy Co. | Thomas C. Mielnik | Abstain | |
| 3 | Mississippi Power | Don Horsley | Affirmative | |
| 3 | New York Power Authority | Christopher Lawrence de Graffenried | Affirmative | |
| 3 | Niagara Mohawk (National Grid Company) | Michael Schiavone | Affirmative | |
| 3 | North Carolina Municipal Power Agency #1 | Denise Roeder | Affirmative | |

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|---|---|---|---|---|
| 3 | Orlando Utilities Commission | Ballard Keith Mutters | Affirmative | |
| 3 | Platte River Power Authority | Terry L Baker | Affirmative | |
| 3 | Potomac Electric Power Co. | Robert Reuter | Affirmative | |
| 3 | Progress Energy Carolinas | Sam Waters | Affirmative | |
| 3 | Public Service Electric and Gas Co. | Jeffrey Mueller | | |
| 3 | Public Utility District No. 1 of Chelan County | Kenneth R. Johnson | Abstain | |
| 3 | Public Utility District No. 2 of Grant County | Greg Lange | Affirmative | |
| 3 | Reliant Energy Services | John Meyer | | |
| 3 | Salt River Project | John T. Underhill | Affirmative | |
| 3 | San Diego Gas & Electric | Scott Peterson | | |
| 3 | Santee Cooper | Zack Dusenbury | Affirmative | |
| 3 | Seattle City Light | Dana Wheelock | Affirmative | |
| 3 | South Carolina Electric & Gas Co. | Hubert C. Young | Affirmative | |
| 3 | Tampa Electric Co. | Ronald L. Donahey | | |
| 3 | Tennessee Valley Authority | Cynthia Herron | Affirmative | |
| 3 | Turlock Irrigation District | Casey Hashimoto | Affirmative | |
| 3 | Wisconsin Electric Power Marketing | James R. Keller | Affirmative | |
| 3 | Xcel Energy, Inc. | Michael Ibold | Negative | View |
| 4 | American Municipal Power - Ohio | Chris Norton | Affirmative | |
| 4 | Consumers Energy Co. | David Frank Ronk | Affirmative | |
| 4 | North Carolina Municipal Power Agency #1 | Andrew Fusco | Negative | View |
| 4 | Northern California Power Agency | Fred E. Young | Affirmative | |
| 4 | Oklahoma Municipal Power Authority | Robin J. Morecroft | Affirmative | |
| 4 | Old Dominion Electric Coop. | Mark Ringhausen | Affirmative | |
| 4 | Seattle City Light | Hao Li | Affirmative | |
| 4 | Seminole Electric Cooperative, Inc. | Steven R. Wallace | Affirmative | |
| 4 | Transmission Access Policy Study Group | William J. Gallagher | | |
| 4 | Wisconsin Energy Corp. | Anthony Jankowski | Negative | View |
| 5 | AEP Service Corp. | Brock Ondayko | Negative | View |
| 5 | Alabama Electric Coop. Inc. | Tim Hattaway | Abstain | |
| 5 | Avista Corp. | Edward F. Groce | Affirmative | |
| 5 | Bonneville Power Administration | Francis J. Halpin | Negative | View |
| 5 | City of Tallahassee | Alan Gale | Affirmative | View |
| 5 | Colmac Clarion/Piney Creek LP | Harvie D. Beavers | Affirmative | |
| 5 | Conectiv Energy Supply, Inc. | Richard K. Douglass | Affirmative | |
| 5 | Constellation Generation Group | Michael F. Gildea | Negative | View |
| 5 | Dairyland Power Coop. | Warren Schaefer | Affirmative | |
| 5 | Detroit Edison Company | Ronald W. Bauer | Affirmative | |
| 5 | FirstEnergy Solutions | Kenneth Dresner | | |
| 5 | Florida Municipal Power Agency | Douglas Keegan | Affirmative | |
| 5 | Florida Power & Light Co. | Robert A. Birch | Affirmative | |
| 5 | Great River Energy | Cynthia E Sulzer | Negative | |
| 5 | JEA | Donald Gilbert | Affirmative | |
| 5 | Lincoln Electric System | Dennis Florom | Affirmative | |
| 5 | Louisville Gas and Electric Co. | Charlie Martin | Affirmative | |
| 5 | Manitoba Hydro | Mark Aikens | Negative | |
| 5 | PPL Generation LLC | Mark A. Heimbach | Affirmative | |
| 5 | Progress Energy Carolinas | Wayne Lewis | Affirmative | |
| 5 | PSEG Power LLC | Thomas Piascik | | |
| 5 | Salt River Project | Glen Reeves | Affirmative | |
| 5 | Seminole Electric Cooperative, Inc. | Brenda K. Atkins | Affirmative | |
| 5 | Southeastern Power Administration | Douglas Spencer | Abstain | |
| 5 | Southern Company Services, Inc. | Roger D. Green | Affirmative | |

| | | | | |
|---|---|---|---|---|
| 5 | Tenaska, Inc. | Scott M. Helyer | Affirmative | |
| 5 | U.S. Army Corps of Engineers Northwestern Division | Karl Bryan | Affirmative | |
| 5 | Wisconsin Electric Power Co. | Linda Horn | Affirmative | |
| 5 | Xcel Energy, Inc. | Stephen J. Beuning | Negative | View |
| 6 | AEP Service Corp. | Dana E. Horton | Negative | |
| 6 | Bonneville Power Administration | Brenda S. Anderson | Negative | View |
| 6 | Consolidated Edison Co. of New York | Rebecca Adrienne Craft | Affirmative | |
| 6 | Entergy Services, Inc. | William Franklin | Abstain | |
| 6 | Exelon Power Team | Pulin Shah | Affirmative | |
| 6 | First Energy Solutions | Alfred G. Roth | Affirmative | |
| 6 | Florida Municipal Power Agency | Robert C. Williams | Affirmative | |
| 6 | Great River Energy | Donna Stephenson | Negative | |
| 6 | Lincoln Electric System | Eric Ruskamp | Affirmative | |
| 6 | Manitoba Hydro | Daniel Prowse | Negative | |
| 6 | New York Power Authority | Thomas Papadopoulos | Affirmative | |
| 6 | Progress Energy Carolinas | James Eckelkamp | Affirmative | |
| 6 | Public Utility District No. 1 of Chelan County | Hugh A. Owen | Affirmative | |
| 6 | Salt River Project | Mike Hummel | Affirmative | |
| 6 | Santee Cooper | Suzanne Ritter | Affirmative | |
| 6 | Seminole Electric Cooperative, Inc. | Trudy S. Novak | Affirmative | |
| 6 | South Carolina Electric & Gas Co. | John E Folsom, Jr. | Affirmative | |
| 6 | Southern Company Generation and Energy Marketing | J. Roman Carter | Affirmative | |
| 6 | Western Area Power Administration - UGP Marketing | John Stonebarger | Affirmative | |
| 6 | Xcel Energy, Inc. | David F. Lemmons | Negative | View |
| 7 | Eastman Chemical Company | Lloyd Webb | Affirmative | |
| 8 | JDRJC Associates | Jim D. Cyrulewski | Affirmative | |
| 9 | California Energy Commission | William Mitchell Chamberlain | Affirmative | |
| 9 | California Public Utilities Commission | Laurence Chaset | | |
| 9 | Commonwealth of Massachusetts Department of Public Utilities | Donald E. Nelson | Affirmative | |
| 9 | Maryland Public Service Commission | James Schafer | Affirmative | |
| 9 | National Association of Regulatory Utility Commissioners | Diane J. Barney | Affirmative | |
| 9 | New York State Public Service Commission | James T. Gallagher | Affirmative | |
| 9 | North Carolina Utilities Commission | Kimberly J. Jones | Affirmative | |
| 9 | Oregon Public Utility Commission | Jerome Murray | Affirmative | |
| 9 | Public Service Commission of South Carolina | Philip Riley | Affirmative | |
| 9 | Public Utilities Commission of Ohio | Klaus Lambeck | Affirmative | |
| 10 | Electric Reliability Council of Texas, Inc. | Kent Saathoff | Affirmative | |
| 10 | Midwest Reliability Organization | Larry Brusseau | Abstain | View |
| 10 | New York State Reliability Council | Alan Adamson | Affirmative | |
| 10 | Northeast Power Coordinating Council, Inc. | Edward A. Schwerdt | Affirmative | |
| 10 | SERC Reliability Corporation | Gerry W. Cauley | Affirmative | |
| 10 | Southwest Power Pool | Charles H. Yeung | Affirmative | |
| 10 | Western Electricity Coordinating Council | Louise McCarren | Affirmative | |
| | | | | |

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## Standard Development Roadmap

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**Development Steps Completed:**

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2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
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4. The JIC assigns development of the standard to NERC on June 15, 2006.
5. Drafting team posts first draft for comments (August 16–September 29, 2006).
6. Drafting team posts second draft with implementation plan for comments (January 9–February 7, 2007).
7. Drafting team posts third draft for comments (March 19–April 17, 2007)

**Description of Current Draft:**

This drafting team did not make any changes to the standard based on comments received during the third posting. The compliance staff has not recommended field testing the compliance elements of this standard. The drafting team will ask the Standards Committee for authorization to post the standard and implementation plan for a 30-day, pre-ballot review.

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| Anticipated Actions | Anticipated Date |
|---|---|
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| 2. First ballot of standards. | |
| 3. Recirculation ballot of standards. | |
| 4. 30-day posting before board adoption. | |
| 5. Board adopts standards. | To be determined |

## Definitions of Terms Used in Standard

*This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.*

**None.**

## A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-1

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability:**

   **4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

      **4.1.1** Transmission lines operated at 200 kV and above.

      **4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

      **4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

      **4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

   **4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

   **4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

   **4.4.** Planning Coordinators.

5. **Effective Dates[1]:**

   **5.1.** Requirement 1, Requirement 2:

      **5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

      **5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

      **5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

   **5.2.** Requirement 3: 18 months following applicable regulatory approvals.

---

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Compliance Enforcement Authority

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
    - **1.5.1** Permissive overreach transfer trip (POTT).
    - **1.5.2** Permissive under-reach transfer trip (PUTT).
    - **1.5.3** Directional comparison blocking (DCB).
    - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

## Standard Development Roadmap

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**None.**

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability:**

**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

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**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — ~~January 1, 2008 or~~ the beginning of the first calendar quarter following applicable regulatory approvals~~, whichever is later~~.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

**5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

**5.2.** Requirement 3: 18 months following applicable regulatory approvals.

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning ~~Authority~~Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Compliance Enforcement Authority

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

## 2. Violation Severity Levels:

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements ~~in~~ R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

## A. Introduction

**1. Title: Transmission Relay Loadability**

**2. Number:** PRC-023-1

**3. Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

**4. Applicability:**

**4.1.** Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

**4.1.1** Transmission lines operated at 200 kV and above.

**4.1.2** Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.1.3** Transformers with low voltage terminals connected at 200 kV and above.

**4.1.4** Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

**4.2.** Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

**4.4.** Planning Coordinators.

**5. Effective Dates[1]:**

**5.1.** Requirement 1, Requirement 2:

**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

**5.1.3** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.

**5.2.** Requirement 3: 18 months following applicable regulatory approvals.

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1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

**R1.1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

**R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

**R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

**R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

**R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

**R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

**R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

**R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

**R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

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[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

**R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

**R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

**R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

**R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

**R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

**R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

**R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

**R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

**R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

**R2.** The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.** The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

**R3.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

**R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

**R3.2.** The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

**R3.3.** The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

## C. Measures

**M1.** The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that each of its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1)

**M2.** The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R2)

**M3.** The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

## D. Compliance

**1.** Compliance Monitoring Process

**1.1. Compliance Monitoring Responsibility**

**1.1.1** Compliance Enforcement Authority

**1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.

**1.3. Data Retention**

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

**1.4. Additional Compliance Information**

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification, or compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Enforcement Authority.

**2. Violation Severity Levels:**

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements. | | Relay settings do not comply with any of the sub requirements R1.1 through R1.13<br>OR<br>Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13. |
| **R2** | Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2. | | | |
| **R3** | | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated. | Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated. | Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.<br>OR<br>Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,<br>OR |

| | | | | |
|---|---|---|---|---|
| | | | | Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated. |

## E. Regional Differences

None

## F. Supplemental Technical Reference Document

**1.** The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | February 12, 2008 | Approved by Board of Trustees | New |

## Attachment A

**1.** This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

**2.** This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

**3.** The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.

**Exhibit D**

**"PRC-023 Reference – Determination and Application of Practical Relaying Loadability Ratings"**

# PRC-023 Reference

# Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Council

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

***Version 1.0***

***August 14, 2006***

# Table of Contents

# Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Generator protection relays
   - 2.4. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

# Requirements Reference Material

## R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

## R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

$V_{L-L}$ = Rated line-to-line voltage

$I_{rating}$ = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating ($I_{rating}$) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

## R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating ($I_{rating}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

## R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

### R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

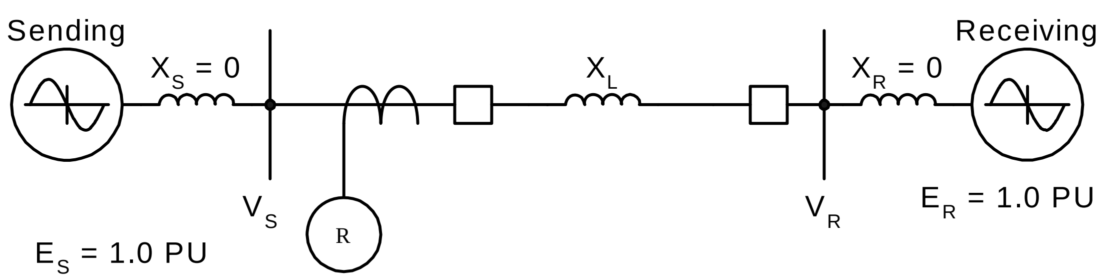



**Figure 1 – Maximum Power Transfer**

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where:

$P$ = the power flow across the transmission line

$V_S$ = Phase-to-phase voltage at the sending bus

$V_R$ = Phase-to-phase voltage at the receiving bus

$\delta$ = Voltage angle between $V_s$ and $V_R$

$X_L$ = Reactance of the transmission line in ohms

[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$I_{real}$ = Real component of current

$V$ = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

$I_{total}$ is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$ (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

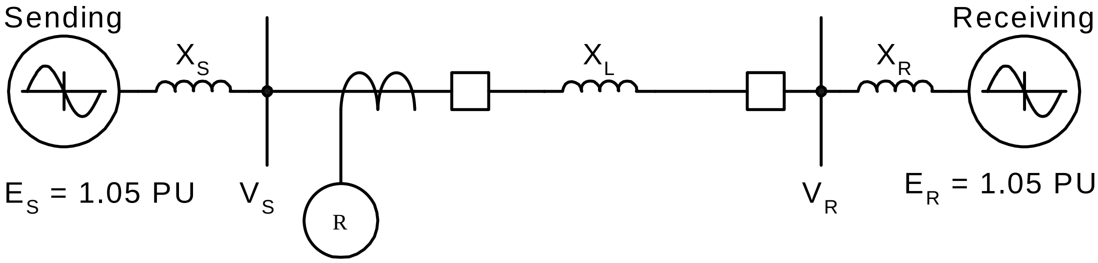



**Figure 2 – Site-Specific Maximum Power Transfer Limit**

The recommended procedure for determining $X_S$ and $X_R$ is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude ($I_{real}$) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

$P_{max}$ = Maximum power that can be transferred across a system

$E_S$ = Thévenin phase-to-phase voltage at the system sending bus

$E_R$ = Thévenin phase-to-phase voltage at the system receiving bus

$\delta$ = Voltage angle between $E_S$ and $E_R$

$X_S$ = Thévenin equivalent reactance in ohms of the sending bus

$X_R$ = Thévenin equivalent reactance in ohms of the receiving bus

$X_L$ = Reactance of the transmission line in ohms

$V$ = Nominal phase-to-phase system voltage

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{(X_S + X_R + X_L)}}$$

Where:

$I_{total}$ = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times $I_{total}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

## R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

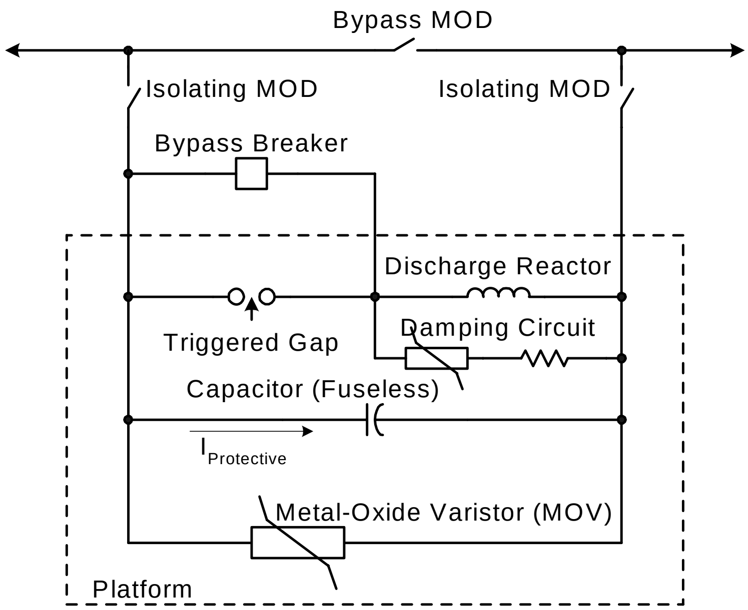



**Figure 3 – Series Capacitor Components**

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

$X_C$ = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because $I_{total}$, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. $I_{total}$ (where $I_{total}$ is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

## R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

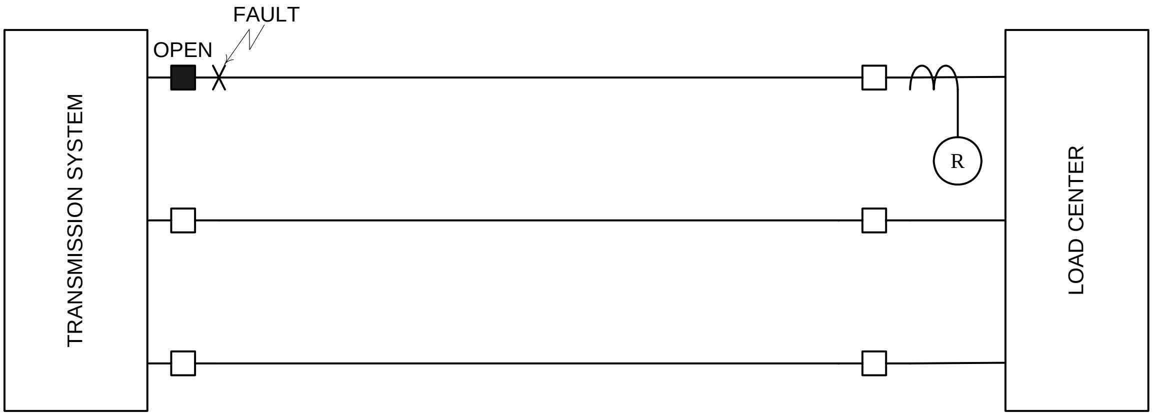



**Figure 4 – Weak Source Systems**

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{V_S{}^2 + V_R{}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current $I_{fault}$ by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$\mathrm{I_{max}} = 1.15 \times \sqrt{2} \times 1.05 \times \mathrm{I_{fault}}$$

$$\mathrm{I_{max}} = 1.70 \times \mathrm{I_{fault}}$$

Where:

$I_{fault}$ is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times $I_{fault}$, where $I_{fault}$ is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

## R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current ($I_{max}$) that the line will experience.

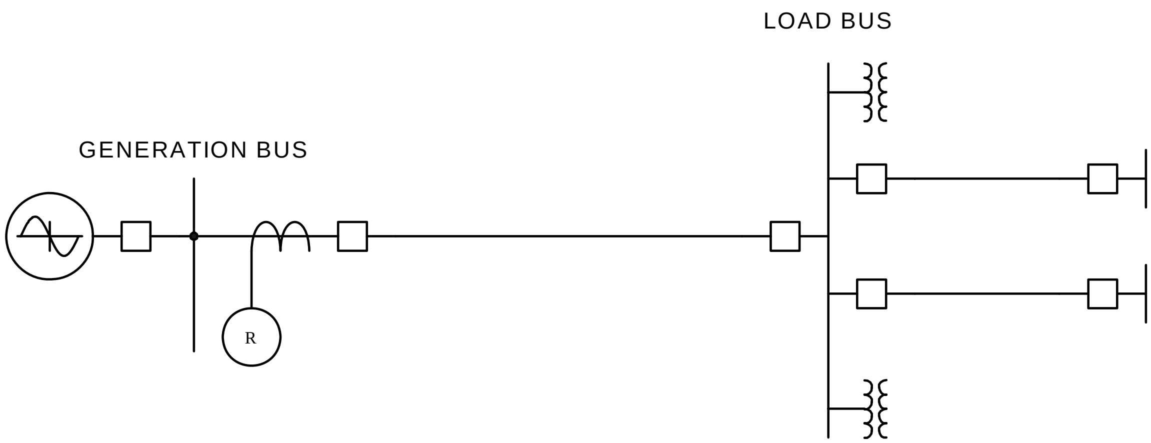



**Figure 5 – Generation Remote to Load Center**

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amps at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}$$

Where:

$V_{relay}$ = Phase-to-phase voltage at the relay location

$N$ = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the $I_{max}$. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

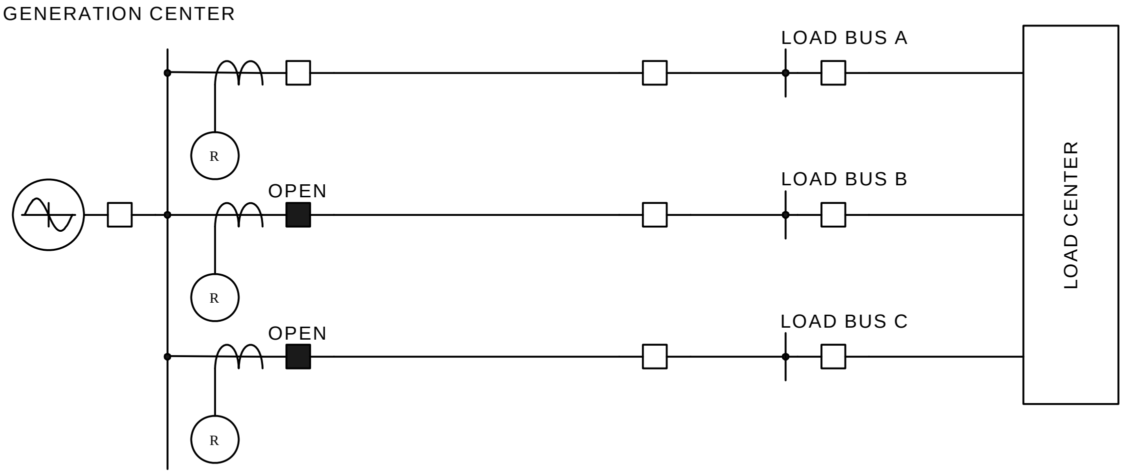



**Figure 6 – Generation Connected to System – Multiple Lines**

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The $I_{max}$ expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds $I_{max}$.

Set the tripping relay so it does not operate at or below 1.15 times $I_{max}$, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$$

## R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

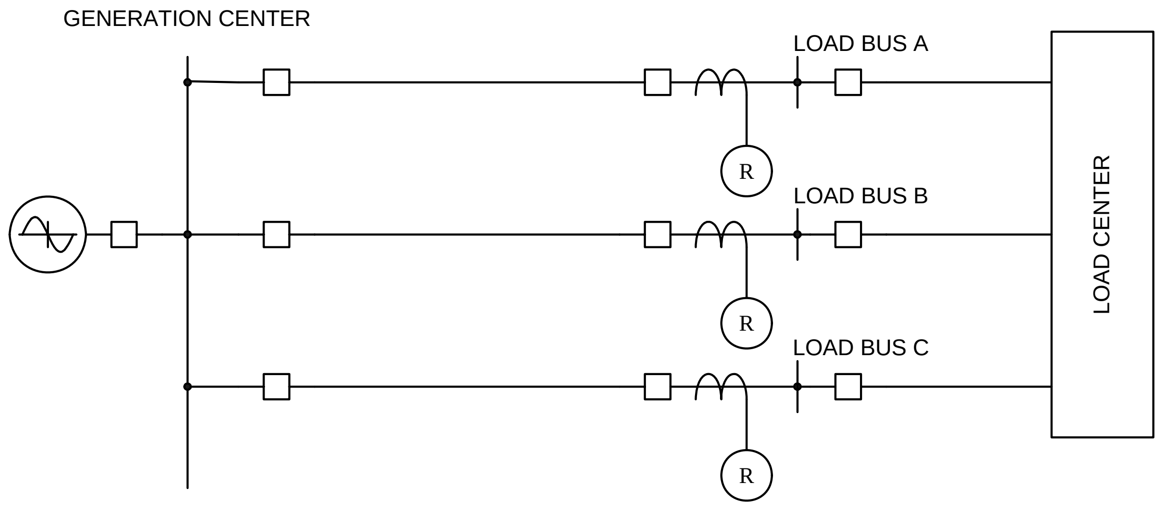



**Figure 7 – Load Remote to Generation**

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow ($I_{max}$) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

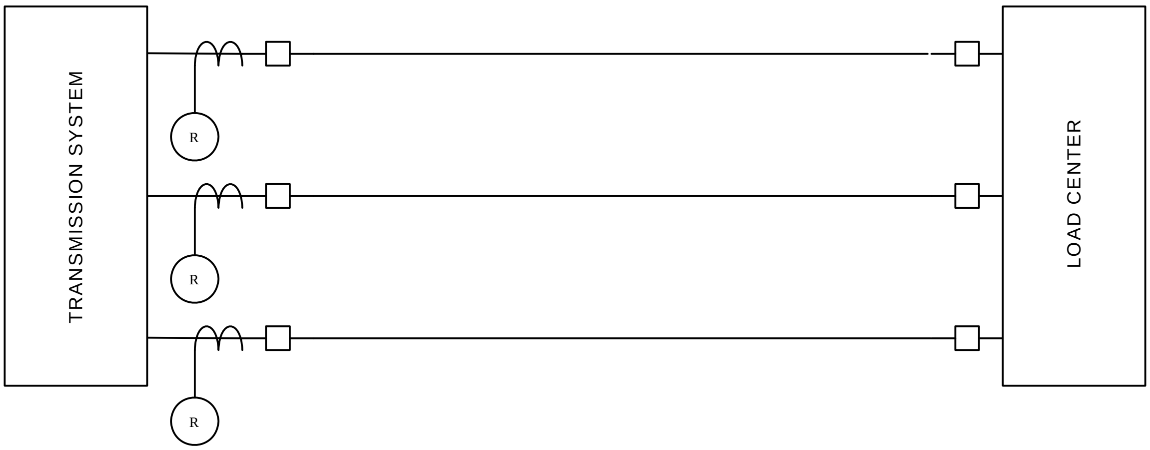



**Figure 8 – Remote Cohesive Load Center**

Also, one must determine the maximum power flow on an individual line to the area ($I_{max}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.

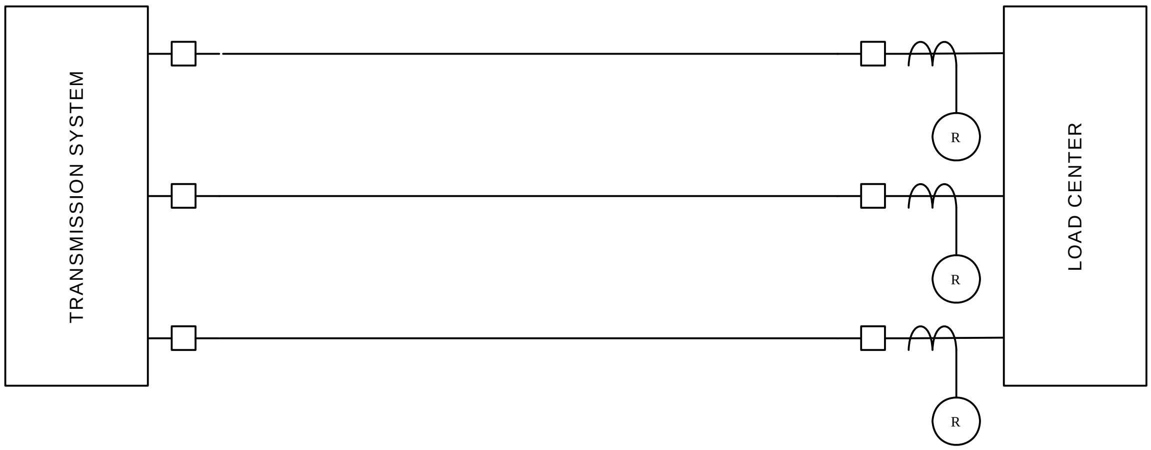



**Figure 9 – Cohesive Load Center Remote to Transmission System**

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow ($I_{max}$)from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

## R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

## R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer.

1. Provide the protective relay set point(s) for all load-responsive relays on the transformer.
2. Provide the reason or basis for the reduced load capability (below 150% of transformer nameplate or 115% of the operator-established emergency rating, whichever is higher) .
3. Verify that no current or subsequent planning contingency analyses identify any conditions where the recoverable flow is less than the reduced load capability (150% of transformer nameplate or 115% of the highest operator-established emergency rating, whichever is higher) and greater than the trip point.

If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100° C and 140° C[5] respectively, justification for the reduced temperature must be provided.

## R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not "overly sensitive," and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

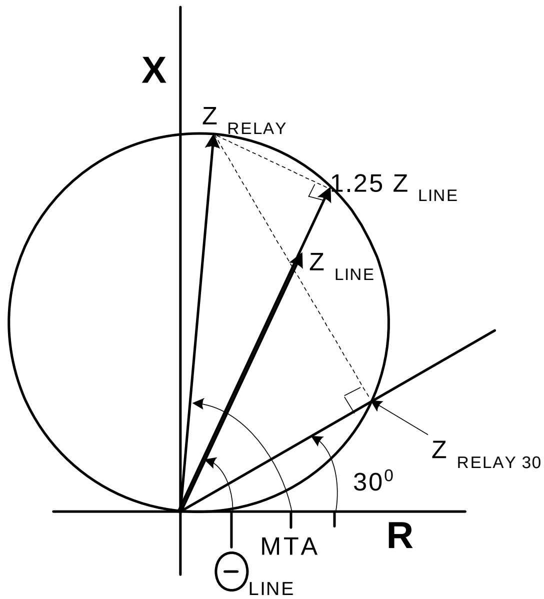



**Figure 10 – Long Line relay Loadability**

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{line}$ = Line impedance

$\Theta_{line}$ = Line impedance angle

$Z_{relay}$ = Relay setting at the maximum torque angle

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(\ MTA - \Theta_{line}\ )}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(\ MTA - 30°\ )}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

## R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

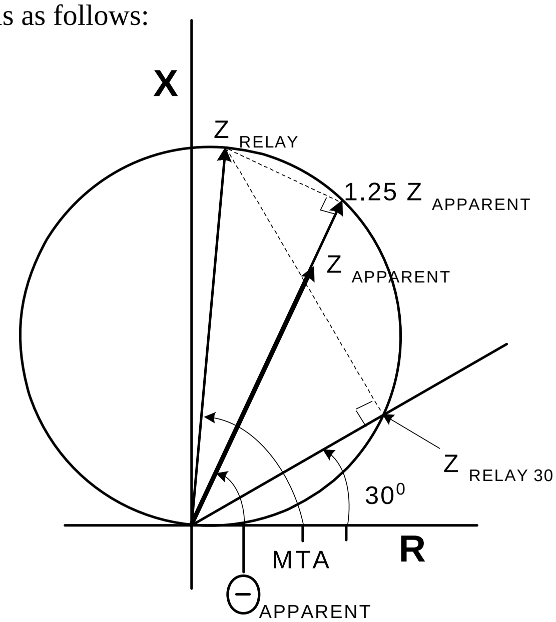



**Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps**

$V_{relay}$ = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed where applicable) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

$Z_{relay}$ = Relay setting at the maximum torque angle.

$MTA$ = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

$I_{trip}$ = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

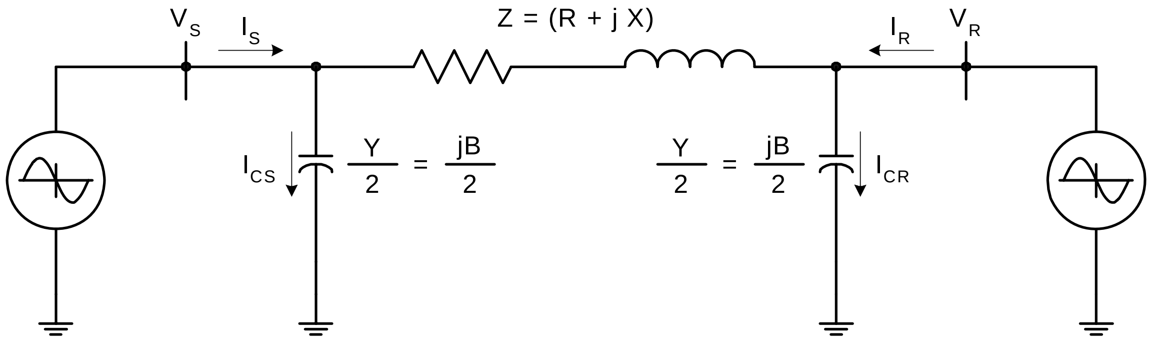
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

# Appendices

# Appendix A — Long Line Maximum Power Transfer Equations




Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\cos(\theta^\circ) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta^\circ)$$

$$Q_{S3-\phi} = \frac{V_S^{\ 2}}{|Z|}\sin(\theta^\circ) - V_S^{\ 2}\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta^\circ)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos(\theta^\circ) + \sin(\theta^\circ)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta^\circ) - |Z|\frac{B}{2} - \cos(\theta^\circ)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{I_{real}^{\ 2} + I_{reactive}^{\ 2}}}$$

Where:

- $P$ = the power flow across the transmission line
- $V_S$ = Phase-to-phase voltage at the sending bus
- $V_R$ = Phase-to-phase voltage at the receiving bus
- $V$ = Nominal phase-to-phase bus voltage
- $\delta$ = Voltage angle between $V_S$ and $V_R$
- $Z$ = Reactance, including fixed shunt reactors, of the transmission line in ohms*
- $\Theta$ = Line impedance angle
- $B$ = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

## Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

## *Unmodified Permissive Overreaching Transfer Trip*

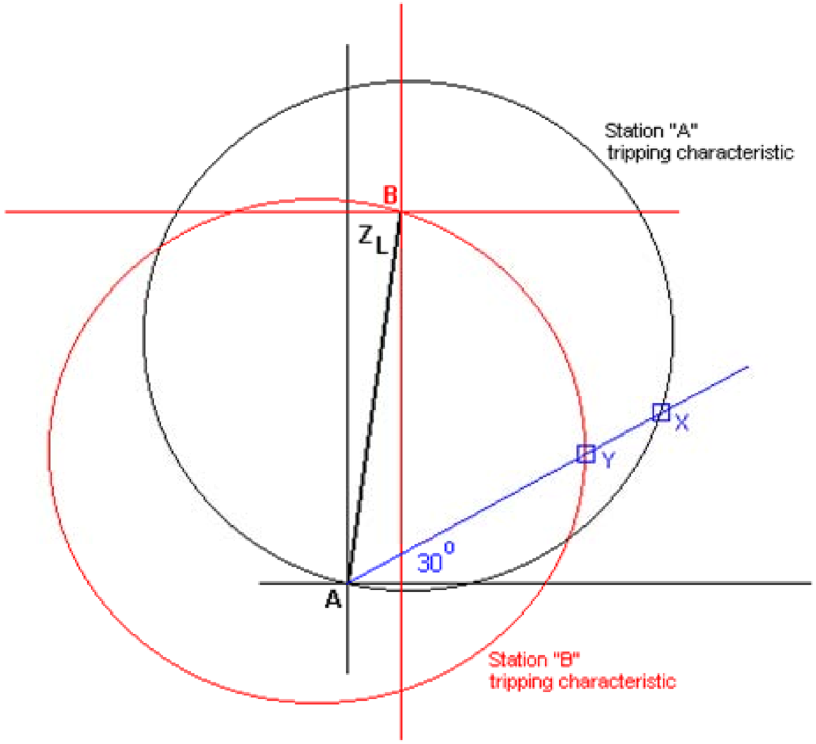



Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station “A” is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point “X” falls outside the tripping characteristic of the relay at Station “B”, preventing tripping at either terminal. Relay “A” becomes susceptible to tripping along its 30-degree line only when point “Y” is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

## *Directional Comparison Blocking*

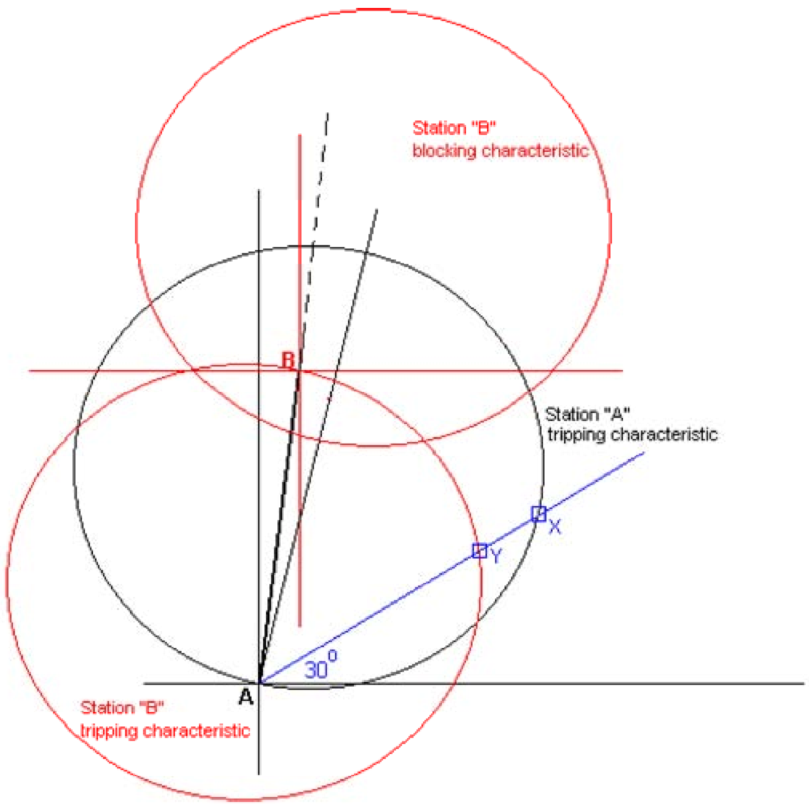



Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

# Appendix C — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, *IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13, *American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz),* 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200