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.