NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Relay Loadability (RELOAD) Drafting Team

April 30, 2007 — 1–3 p.m. Eastern Daylight Saving Time

WebEx and Conference Call
☎ Consortium conference server at phone number 1(732)694-2061
Conference code is 1156043007
WebEx Site: https://nerc.webex.com/
WebEx Meeting number: 715 639 248
WebEx Meeting password: standards

Agenda

1) Administrative

   a. Roll call — Harry Tom

      - Charles W. Rogers — Consumers Energy Co.
      - Thomas Wiedman — Wiedman Power System Consulting Ltd.
      - David Angell — Idaho Power Company
      - Joseph Burdis — PJM Interconnection, L.L.C.
      - W. Mark Carpenter — TXU Electric Delivery Co.
      - Jim Ingleson — New York Independent System Operator
      - Richard Maxwell —
      - Henry Miller — AEP Service Corp.
      - Ronald G. Parsons — Alabama Power Company
      - Philip Tatro — National Grid USA
      - Philip B. Winston — Georgia Power Company
      - Richard Young — American Transmission Company, LLC
      - Robert W. Cummings — North American Electric Reliability Corporation
      - Maureen E. Long — North American Electric Reliability Corporation
      - Richard Schneider — North American Electric Reliability Corporation
      - Harry Tom — North American Electric Reliability Corporation

   b. Antitrust Compliance Guidelines (**Attachment 1**) — Harry Tom

2) Review Implementation Plan — Charles Rogers

   a. Draft responses to each comment submitted on the third posting of the standard (**Attachment 2a**) — Charles Rogers

   b. Modify the standard (**Attachment 2b**) based on discussion of comments submitted on the third posting of the standard — Charles Rogers

c. Discuss disposition of the standard. The drafting team must decide whether to recommend to the Standards Committee to move the standard to balloting. — Charles Rogers

3) Summarize action items — Charles Rogers

4) Select date and time for the next meeting (if any) — Charles Rogers

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NERC Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and

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adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

The Relay Loadability standard requesters thank 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 requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 14 sets of comments, including comments from 50 different people from 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending .

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	✓									
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)	MISO		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Terry Bilke (G5)	MISO										✓
28.	Carol Gerou (G5)	MP										✓
29.	Mike Brytowski (G5)	MRO										✓
30.	Randy MacDonald (G2)	NBSO		✓								
31.	Herb Schrayshuen (G2)	NGRID	✓									
32.	Michael Schiavone (G2)	NGRID	✓									
33.	Michael Rinalli (G2)	NGRID	✓									
34.	Murale Gopinathan (G2)	Northeast Utilities	✓									
35.	Guy V. Zito	NPCC										✓
36.	Al Boesch (G5)	NPPD										✓
37.	Greg Campoli (G2)	NYISO		✓								
38.	Mike Calimano (I) (G4)	NYISO		✓								
39.	Ralph Rufrano	NYPA	✓									
40.	Al Adamson (G2)	NYSRC										✓
41.	Todd Gosnell (G5)	OPPD										✓
42.	Richard J. Kafka (G1)	Pepco Holdings, Inc. – Affiliates	✓									
43.	Alicia Daugherty (G4)	PJM		✓								
44.	Alvin Depew (G1)	Potomac Electric Power Company	✓									
45.	Evan Sage (G1)	Potomac Electric Power Company	✓									
46.	Charles Yeung (G4)	SPP		✓								
47.	Jim Haigh (G5)	WAPA										✓
48.	Neal Balu (G5)	WPSR										✓
49.	David Lemmons (G3)	Xcel Energy						✓				
50.	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:

Question #1			
Commenter	**Yes**	**No**	**Comment**
Pepco Holdings, Inc.	☑		
Hydro-Québec TransÉnergie	☑		
IESO	☑		
NPCC CP9 RSWG	☑		
Entergy	☑		
FirstEnergy	☑		
IRC Standards Review Committee	☑		
ISO New England	☑		
ITC Transmission	☑		
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

Question #1			
Commenter	**Yes**	**No**	**Comment**
			according to the NERC Functional Model.
Response:			
Manitoba Hydro			No comment.
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:

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:			
Hydro-Québec TransÉnergie	☑		
IESO		☑	
NPCC CP9 RSWG		☑	
Entergy		☑	
FirstEnergy	☑		
IRC Standards Review Committee		☑	
ISO New England		☑	
ITC Transmission		☑	
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:			
Manitoba Hydro		☑	
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:			
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

Question #2			
Commenter	**Yes**	**No**	**Comment**
			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:			
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:

Question #3			
Commenter	**Yes**	**No**	**Comment**
Pepco Holdings, Inc.	☑		
Response:			
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. 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 equipment determined from an impact based methodology without specifying voltage.
Response:			
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. 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 Bulk Electric System" be moved from "Severe" to the "High level".
Response:			
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. 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:			
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. 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:			
FirstEnergy	☑		
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

Question #3			
Commenter	**Yes**	**No**	**Comment**
			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. 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".
Response:			
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:			
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:			
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:			
Manitoba Hydro		☑	MH feels that some of our comments during the last two rounds of commenting periods have not been addressed. Mainly: 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. 2) Regarding R13, MH does not agree adding an 15% margin to the loading limitation on

Question #3			
Commenter	**Yes**	**No**	**Comment**
			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:			
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:			
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. 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.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response:			
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. 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:			

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 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).

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.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day, pre-ballot period.	March 15–April 13, 2007
2. First ballot of standards.	April 16–25, 2007
3. Recirculation ballot of standards.	May 1–10, 2007
4. 30-day posting before board adoption.	To be determined
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.

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.

4.2. Generator Owners with 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 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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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 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.