

### **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 NERC Reliability Standards Glossary of Terms or the MRO 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 Midwest Reliability Organization (MRO) Glossary. NERC and MRO defined terms are capitalized in the standard.*

None

**A. Introduction**

- 1. Title:** System Performance Assessments
- 2. Number:** TPL-503-MRO-02
- 3. Purpose:** To ensure that valid system performance assessments are conducted to demonstrate that the Bulk Electric System meets appropriate contingency conditions within the MRO.
- 4. Applicability**
  - 4.1** Planning Coordinator
  - 4.2** Transmission Planner
- 5. Effective Date:** 1st day of the 1st calendar quarter after applicable regulatory approval, this standard will be effective. In those jurisdictions where no regulatory approval is required, this standard becomes effective on the 1st day of the 1st calendar quarter after NERC Board of Trustees adoption.

**B. Requirements**

- R1.** Each Planning Coordinator and Transmission Planner shall demonstrate through valid assessment(s) that its portion of the Bulk Electric System meets the contingency conditions as defined in the Table 1: MRO System Performance Table which are in addition to the conditions defined in the currently approved NERC TPL standard(s). [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]

To be valid, the assessment shall:

- 1.1** Be performed annually.
- 1.2** Be conducted beyond the five-year horizon only as needed to address identified criteria violations that may have longer lead-time solutions.
- 1.3** Include current or past studies and/or simulation testing that:
  - 1.3.1** Demonstrate that System Performance meets the MRO System Performance Table for all categories in the same way that the Planning Coordinator and Transmission Planner demonstrates it meets the most currently approved NERC TPL standard(s).
  - 1.3.2** Are performed with the applicable facility thermal rating or system voltage limit for each NERC contingency category.
  - 1.3.3** For Normal Clearing of single line to ground (SLG) faults, include consideration of both single pole tripping if enabled with successful reclosing and single pole tripping if enabled with unsuccessful reclosing due to permanent SLG fault followed by Normal Clearing.

- 1.3.4** Demonstrate that the System is capable of readjustment within the readjustment period<sup>1</sup> so that facility loadings are within Normal Facility Ratings and facility voltage levels are within Normal system voltage limits following a disturbance and the readjustment period. Permissible automatic and manual system readjustments are defined in the MRO System Performance Table (Table 1 notes 2 and 3).
- 1.4** Include any two (2) adjacent (vertically or horizontally) circuits on common structure provided that the circuits share a common structure for more than one (1) mile in length and each combination produces more severe system results or impacts for contingency testing to meet regional and NERC system performance. The Planning Coordinator and/or Transmission Planner may ask for a variance (refer to the MRO Standards Process Manual) to the common structure inclusion on a case by case basis for distances that are longer than one (1) mile (e.g., station entrance, river crossings).
- 1.5** Include a safety margin on top of the actual or estimated fault clearing time to account for uncertainties in the operating time of the protection system (relay, communication path, breaker, and intentional delay (such as breaker failure and transfer trip.) The Planning Coordinator and/or the Transmission Planner shall document the basis for the safety margin.
- R2.** Each Planning Coordinator and Transmission Planner shall have corrective plan(s) for its portion of the Bulk Electric System to achieve the required system performance, when studies or system simulations indicate an inability of the systems to respond as prescribed in Requirement R1. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R3.** Each Planning Coordinator and Transmission Planner shall have documentation of the results of these valid assessments and corrective plans for its portion of the Bulk Electric System. [*Violation Risk Factor: Lower*] [*Time Horizon: Operational Planning*]
- R4.** Each Planning Coordinator and Transmission Planner shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment defined in Requirement R1 through Requirement R3. [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]

## C. Measures

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<sup>1</sup> For example, the length of the readjustment period for a given contingency event that results in the Normal Facility Rating of a facility to be exceeded after a single contingency shall be less than or equal to the finite period that the facility owner has agreed the exceeded facility can withstand at the Emergency Rating. However, the length of the readjustment period after a single contingency that results in exceeding an Interconnection Reliability Operating Limit (IROL) shall be less than or equal to the IROL T<sub>v</sub>. The NERC Glossary defines IROL T<sub>v</sub>. Also, FAC-010 includes a criterion for developing T<sub>v</sub>.

- M1.** The Planning Coordinator and Transmission Planner shall each have evidence that valid assessments have been developed in accordance with Requirement R1.
- M2.** The Planning Coordinator and Transmission Planner shall each have evidence that corrective plan(s) have been developed for its portion of the Bulk Electric System in accordance with Requirement R2.
- M3.** The Planning Coordinator and Transmission Planner shall each have evidence that documentation of results of its assessments and corrective plans have been reported in accordance with Requirement R3.
- M4.** The Planning Coordinator and Transmission Planner shall provide evidence that they have jointly determined the responsibilities for performing the required studies defined in Requirement R1 through Requirement R3 per Requirement R4.

**D. Compliance**

**1. Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

ERO delegated to Midwest Reliability Organization

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

Annually

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Violation Severity Levels**

<b>R #</b>	<b>Lower VSL</b>	<b>Moderate VSL</b>	<b>High VSL</b>	<b>Severe VSL</b>
<b>R1</b>	No safety margins were included when using estimated model data.	Valid assessments for the longer-term planning horizon are not available.	Current or past studies and/or simulated studies were not included	Valid assessments for the near-term planning horizon are not available per Requirement R1.
<b>R2</b>	Not applicable	Corrective plans for the longer-term planning horizon are not available.	Not applicable	Corrective plans for the near-term planning horizon are not available per Requirement R2.
<b>R3</b>	Not applicable	Not applicable	Not applicable	Evidence of reporting assessments and corrective plans was not provided per Requirement R3.
<b>R4</b>	Not applicable	Not applicable	Not applicable	The Planning Coordinator and Transmission Planner failed to provide identification of responsible entities for performing studies and planning assessments per Requirement R4.

**Version History**

<b>Version</b>	<b>Date</b>	<b>Action</b>	<b>Change Tracking</b>

**Table 1: MRO SYSTEM PERFORMANCE TABLE<sup>1</sup>**

NERC Categories	Transient Voltage Deviation Limits	Rotor Angle Oscillation Damping Ratio Limits
No Contingencies	Nothing in addition to NERC Requirements	
Single Contingency (See Notes 2 and 6)	Minimum 0.70 p.u. at any bus (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
Multiple Contingency (See Notes 2, 3 and 6)	Minimum 0.70 p.u. at any bus (See Note 5)	Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7)
Extreme Event (See Note 4)	Nothing in addition to NERC Requirements	

## Notes:

1. The MRO System Performance Table including the notes applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to the end of the allowed readjustment period as described in R1.3.4).
2. The following summarizes automatic and manual readjustments that are permissible for single and multiple contingencies.
  - A. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units.
  - B. Capacitor and reactor switching - The number of capacitors and reactors which may be switched is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period.
  - C. Adjustment of Load Tap Changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the allowed readjustment period.
  - D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.
  - E. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.
  - F. Generation rejection to the extent possible within the allowed readjustment period. Shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.
  - G. Transmission reconfiguration - Automatic and operator initiated tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.
  - H. Automatic or manual tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Point-to-Point Transmission Service to the extent possible within the allowed readjustment period. Curtailment of Firm Transmission Service within the readjustment period is permitted only to prepare for the next contingency.
3. The following additional readjustment may be considered for all multiple contingencies.

- A. Automatic or manual tripping of firm Network or Native Load or curtailment of or predetermined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
4. The following additional readjustments may be considered for all extreme events.
  - A. Planned and/or controlled islanding - Automatic underfrequency load shedding, as specified in NERC PRC-006-0, is permitted to arrest declining frequency and generation rejection is permitted to arrest increasing frequency in order to assure continued operation within the resulting islands.
  - B. Automatic undervoltage load shedding is permissible to arrest declining voltages and prevent widespread voltage collapse.
5. The voltage of 0.7 per unit is the point at which load dropping begins to occur due to motor contactors dropping out and induction motors stalling and also the point where sensitive equipment (e.g. power electronics) begin to drop out.
6. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for single contingencies, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for multiple contingencies, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.
7. Damping is required during the initial transient period following the disturbance (up to 20 seconds). The machine rotor angle damping ratio is determined by appropriate modal analysis (e.g. Prony analysis). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.90 or the damping factor must be greater than 10%. (The Rotor Angle Oscillation Damping Ratio Limits were derived from the SPPR criteria.)