Transmission Planning and Protection

Transmission Planning Criteria

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Purpose

This document outlines the criteria that are developed, maintained, and implemented by FirstEnergy's (FE) Transmission Planning and Protection (TPP) department. TPP has planning responsibility for FE-owned transmission and transmission <100 kV facilities.

1. Key Terms and Definitions

1.1. **Bulk Electric System (BES)** – Facilities ≥100 kV. For transformers, the secondary side voltage is used to determine if the facility is part of the BES or not.

1.2. **NERC** – North American Electric Reliability Corporation

1.3. **RF** – ReliabilityFirst

1.4. **RTO** – Regional Transmission Organization; PJM fills this role for FE

1.5. **Transmission** (for the purposes of this document)

1.5.1. Transmission-level voltages are defined as 100 kV and above.

1.5.2. Transmission <100 kV are generally voltage levels ≥23 kV but less <100 kV.

1.5.3. References in this document to "transmission" apply to both standard transmission-level voltages and to transmission <100 kV facilities as defined above.

1.5.4. Note: Systems with voltages in the <100 kV range that are not normally operated in a networked manner and with no capability to do so are considered Distribution facilities and are not covered by this document.

1.6. **50/50 peak load** – Forecast for which there is a 50% probability that the actual peak load for the season will be less than the forecast and a 50 % probability that it will be higher.

1.7. **90/10 peak load** – Forecast for which there is a 90% probability that the actual peak load for the season will be less than the forecast and a 10% probability that it will be higher.

1.8. **Double Circuit Tower Line** – Any pair of transmission lines (breaker to breaker) that share the same set of structures for at least one mile in total.

1.9. **Generation Dispatch** – Process of matching generation output to load requirements in a defined area.

1.10. **Intermediate Load Level** – Normally 70% of the 50/50 summer peak load forecast.

1.11. **Light Load Level** – Normally ranges from 30% to 55% of the seasonal peak load forecast.

1.12. **Spring Season Model** - For purposes of modeling, use load scaled to the April peak.

1.13. **Summer Season Ratings** – For purposes of the equipment ratings used in planning evaluations, summer season shall be from April 15 through October 15.

1.14. **Fall Season Model** – For purposes of modeling, use load scaled to the October peak.

1.15. **Winter Season Ratings** – For purposes of the equipment ratings used in planning evaluations, Winter Season shall be from October 15 through April 15.

2. Introduction

2.1. Objectives

2.1.1. This reference guide is intended to meet or exceed all applicable minimum requirements of NERC, RF, and PJM.

2.1.2. The applicable requirements are defined in documents periodically developed and reviewed by these organizations with industry wide input.

2.1.3. In the event that one of these organizations imposes more stringent requirements than those defined in this document, those more stringent requirements will prevail.

2.2. Scope

2.2.1. This document covers FE planning criteria associated with the transmission systems, including the following:

- Voltage level criteria
- Voltage and transient stability requirements
- Load curtailment criteria
- Voltage regulation requirements
- Reactive power requirements
- Short circuit requirements.
- Note: Loadability criteria for circuits including transformers are described in separate documents.

2.2.2. Transmission requirements covering loadability, connection requirements, and system protection are included in other TPP documents, as listed in the *Related Documents* section of this document.

3. Normal and Emergency Equipment Loadability Limits

3.1. Circuit Loadability

3.1.1. Circuit ratings are unique for a given season (summer or winter) and consist of:

- Normal
- Long Term Emergency (LTE)
- Short Term Emergency (STE)
- Load Dump (LD)

3.1.2. In general, the STE and LTE ratings of a transmission circuit are identical.

- There may be instances where the STE is greater than the LTE depending on the limiting circuit component.
- Load Dump ratings are only applicable in real time operations.

3.1.3. Changes in circuit rating resulting from the loss of parallel facilities in a ring bus or other switching arrangements shall be considered in the analysis of extended forced or scheduled outage analysis.

3.2. **Transformer Rating Definitions**

The following rating definitions are utilized for transformers:

3.2.1. **Normal Rating** – Defined in the *Transformer Loadability Guide and Rating Methodology* document as the rating applicable for a daily peak load cycle that can be accommodated repeatedly, during the defined season, over the life of the transformer.

3.2.2. **LTE Rating** – The 6-month transformer rating as defined in the *Transformer Loadability Guide and Rating Methodology* document is used as the LTE rating for all transformers. The LTE rating is defined as the daily peak load cycle that can be accommodated repeatedly for 6 month period.

3.2.3. **STE Rating** – The 4-hour transformer rating as defined in the *Transformer Loadability Guide and Rating Methodology* document is used as the STE rating for all transformers.

3.3. **Ratings Used in Power Flow Models**

The following ratings will be used in all power flow models:

Table 1: Ratings for Power Flow Models

	BES Facilities		All Other Facilities	
	Transformers	Lines	Transformers	Lines
Rate 1	Normal	Normal	Normal	Normal
Rate 2	STE	STE	LTE	STE
Rate 3	LD	LD	LD	LD

4. Normal and Emergency Voltage Limits and Regulation

4.1. **Steady State Voltage Level Limits**

4.1.1. The limits for voltages (in per unit of nominal bus voltage) on transmission buses for normal and emergency operating conditions are listed in *Table 2: Voltage Limits*.

- Note: The Normal and Emergency Minimum limits above are values following system adjustments and not the immediate post contingency value.

Table 2: Voltage Limits

Limit	500 kV	230/ 345 kV	138/115 kV		69/46/34.5 kV	25/23 kV
	ALL	ALL	PJM BES	PJM Non-BES	ALL	ALL
Maximum	1.10	1.05	1.05	1.05	1.05	1.075
Normal Minimum	1.00	0.95	0.95	0.95	0.92	0.92
Emergency Minimum	0.97	0.92	0.92	0.90	0.90	0.90
Maximum Deviation * (Pre- to Post-Contingency and On-to-Off Peak)	0.05	0.08	0.10	0.10	0.10	0.10

* Refer to *Section 4.3, Fast-Switched Capacitor Voltage Criteria*.

4.1.2. The voltage limits defined above do not preclude more restrictive voltage screening limits which may be requested by nuclear power plants to support safety related equipment. Power plant owners must provide rationale for requesting a deviation from these standard voltage ranges and any more restrictive voltage screening limits will be mutually agreed upon by the power plant and the transmission owner. FE adheres to specific voltage limits found in the latest Nuclear Plant Interface Agreements (NPIRs).

4.1.3. These more restrictive screening limits shall be used during the normal assessment processes and if violations are identified, the Planning Engineer shall issue a written notification to the Nuclear Plant Owner describing the nature of the NPIR violation. The Transmission Owner is not obligated to build or otherwise modify the transmission system to support these more restrictive voltage screening limits.

4.1.4. The voltage levels apply to steady state voltage levels and not to momentary voltage excursions or transients such as those associated with the switching of FE transmission or customer facilities. The TPP NUC-001 Subject Matter Expert will review all control files prior to performing assessments to ensure that the correct voltages are used.

4.2. Voltage Change as Result of Capacitor Switching

4.2.1. Under normal operating conditions, the steady state change in system voltage caused by capacitor switching shall not exceed 3%.

4.2.2. All new capacitors shall be evaluated with the strongest single source out of service to ensure that the steady state voltage change caused by switching the capacitor does not exceed the bandwidth of the capacitor automatic voltage control.

4.3. Fast-Switched Capacitor Voltage Criteria

When studies indicate that the contingency voltage deviation is greater than the maximum voltage deviation value specified in *Table 2: Voltage Limits*, it may be acceptable to use fast switched capacitors to address this criteria violation.

4.3.1. If post-contingency voltage remains above 85%, then fast switched capacitors with switching times in the range of 3 to 5 seconds can be used to address the criteria violation.

4.3.2. If post-contingency voltage drops below 85%, or if the case is non-convergent, then a dynamic stability study is required to determine if using a fast-switched capacitor is adequate to prevent voltage collapse and if so, to define the required switching times.

5. Solution Parameters Used in Planning Studies

Note: Limits on controls apply only to those facilities in the FE footprint being studied and need not be applied across the entire case.

5.1. **Voltage Deviation** – For evaluation of voltage deviation criteria:

5.1.1. Generators are set to regulate their terminal voltage to the pre-contingency voltage level.

5.1.2. All phase shifters, transformer taps, switched shunts, and DC lines are locked at their pre-contingency positions.

5.1.3. Static VAR Compensators (SVC) and fast-switched capacitors are allowed to adjust.

5.2. **Emergency Minimum Voltage** – For evaluation of steady state emergency minimum voltage:

5.2.1. Generators are set to regulate their associated transmission level bus.

5.2.2. All transformer taps, switched shunts, SVC, and DC lines are allowed to adjust.

5.2.3. Phase shifters are locked at their pre-contingency positions.

5.3. **Thermal** – For evaluation of thermal criteria:

5.3.1. Generators will be set to regulate their associated transmission level bus.

5.3.2. All transformer taps, switched shunts, SVC, and DC lines are allowed to adjust.

5.3.3. Phase shifters may be allowed to adjust if they could impact the area being studied.

6. Thermal and Voltage Assessment Requirements

Note: Refer to Appendix A, Summary of Planning Criteria, for a tabular summary of the criteria detailed in Sections 6.1, 6.2, and 6.3.

6.1. Normal Loading/Voltage Analysis (NERC Category P0)

6.1.1. The FE transmission system will be developed so that it can be operated at the expected peak and at lower load levels, such that with the transmission system in its normal configuration:

- The loading on each transmission facility shall not exceed the seasonal normal rating of the facility, and
- The voltage at each transmission substation shall be within the normal range as specified in *Section 4.1*.

6.2. Contingency Loading/Voltage Analysis

The FE transmission system is developed so that it can be operated at the expected peak and at lower load levels, such that the following contingencies will not cause transmission circuit loadings to exceed applicable ratings, will not violate the emergency voltage criteria as specified in *Section 4.1*, and will not cause voltage or angular instability or cascading outages (See *Section 10, Cascade Analysis*).

Uncontrolled load loss impacting the BES is not permissible for NERC category P1 through P7 contingencies; however, controlled load shedding may be permissible under certain contingency conditions.

- Additional information regarding load loss criteria is detailed in *Section 11, Loss of Load Criteria.*

When performing contingency loading and voltage analysis, similar contingencies in neighboring systems and their impact on the FE system shall be considered.

6.2.1. Single Contingency (NERC Category P1)

6.2.1.1 BES Transmission Facilities

- Single contingency analysis under this section shall be performed with the single most significant generator modeled out of service as a preexisting system condition.
- The loss of any single generating unit, transmission line, transformer, capacitor, or single pole of a bi-polar DC line will not cause transmission loading to exceed the seasonal STE rating of any transmission facility. Voltages on the remaining networked system must meet the steady state voltage level limits criteria as specified in *Section 4.1*. Voltages at buses left being fed radially by a single facility ≥100 kV following the outage must meet the steady state voltage level limits criteria for the PJM non-BES as specified in *Section 4.1*.
- For purposes of this requirement, all transmission elements included in the primary zone of protection of any generator, transmission line, or transformer shall be considered to be part of the single element testing. Automatic shedding of load is not permitted to maintain facilities within thermal and voltage limits.
- After the outage, the system must be capable of readjustment so that all transmission equipment will be loaded within the normal ratings and within normal voltage limits. Readjustment can include the re-dispatch of generation or switching operations to reconfigure system topology. Any proposed adjustment needs to be tested in combination with other single contingencies and be able to meet the requirements in *Section 6.2.5*. Load shedding is not permitted to return the system to within normal limits.

6.2.1.2 All Non-BES Transmission Facilities

- Single contingency analysis under this section shall be performed with the single most significant generator modeled out of service as a preexisting system condition.
- The loss of any single generating unit, transmission line, transformer, capacitor, or single pole of a bi-polar DC line will not cause loading to exceed the seasonal LTE of any transformer or the STE rating of any transmission line, violate either the maximum deviation or the emergency minimum voltage criteria as specified in *Section 4.1*.
- For purposes of this requirement, all transmission elements included in the primary zone of protection of any generator, transmission line, or transformer shall be considered to be part of the single element testing.
- For situations where the primary zone of protection includes more than one transmission element (line and/or transformer) and there is the ability to isolate the faulted element and restore the non-faulted elements within 5 minutes, transmission loads shall not exceed seasonal STE immediately following the contingency and shall not exceed the seasonal LTE after the faulted equipment is isolated.

6.2.2. Subsequent Contingency (NERC Category P3 & P6)

6.2.2.1 BES Transmission Facilities

- After occurrence of the first outage and the readjustment of the system, a subsequent outage of any remaining single generating unit, transmission line, transformer, capacitor, or single pole of a bi-polar DC line will not cause loadings to exceed the seasonal STE rating of any transmission facility or violate either the maximum deviation or the emergency minimum voltage criteria as specified in *Section 4.1*.
- Automatic shedding of load, up to the limits detailed in *Section 11, Loss of Load Criteria*, is permitted to maintain facilities within thermal and voltage limits
- In situations where the subsequent outage results in a pocket of load being served radially by a single ≥100 kV facility, manual load shedding, up to the limits detailed in *Section 11, Loss of Load Criteria*, is permitted to maintain facilities within thermal and voltage limits.

6.2.2.2 Non-BES Transmission Facilities

- There are no NERC, RF, or FE criteria regarding Category P3 or P6 analysis of non-BES facilities.

6.2.3. Multiple Element Outage (NERC Category P2, P4, P5 & P7)

6.2.3.1 BES Transmission Facilities

- The loss of any double-circuit transmission line, bipolar DC line, faulted circuit breaker, bus section, or the combination of facilities resulting from a line fault coupled with a stuck breaker shall not cause loadings to exceed the seasonal STE rating of any transmission facility or violate either the maximum deviation or the emergency minimum voltage criteria as specified in *Section 4.1*.
- Automatic shedding of load, up to the limits detailed in *Section 11, Loss of Load Criteria*, is permitted to maintain facilities within thermal and voltage limits.
- In situations where the outage results in a pocket of load being served radially by a single ≥100 kV facility, manual load shedding, up to the limits detailed in *Section 11, Loss of Load Criteria*, is permitted to maintain facilities within thermal and voltage limits.

6.2.3.2 Non-BES Transmission Facilities

- There are no NERC, RF, or FE criteria regarding Category P2, P4, P5, and P7 analysis of non-BES facilities.
- Due to specific requirements of the New Jersey BPU, the JCP&L 34.5 kV system in the Barnegat Peninsula area shall be planned and constructed to meet N-2 planning criteria. Specifically, for faults located on submarine cables or any transmission/transmission <100 kV feeder crossing Barnegat Bay, the system must be planned for the loss of any two water crossing feeders.
    - Following the N-2 event, the system must be capable of readjustment so that all transmission equipment will be loaded within the normal ratings and within normal voltage limits. Load shedding is not permitted to return the system to within normal limits.

6.3. Maintenance Condition Contingency Analysis

The FE transmission system will be developed so that at Spring/Fall Peak and lower load levels, a single transmission element can be removed for maintenance and the following unscheduled contingencies:

- Will not cause transmission circuit loadings to exceed applicable ratings
- Will not cause instability or cascading outages
- Will not violate the emergency voltage criteria as specified in *Section 4.1*.

The ability to withstand these contingencies for non-firm transfer conditions is not required.

6.3.1. BES Transmission Facilities

- With a pre-existing outage of any single generating unit, transmission line, transformer, capacitor, single pole of a bi-polar DC line, the additional loss of any single generating unit, transmission line, transformer, circuit breaker, capacitor, or single pole of a bi-polar DC line will not cause transmission loading to exceed the seasonal STE rating of any transmission facility or violate either the maximum deviation or the emergency minimum voltage criteria as specified in *Section 4.1*.
- For purposes of this requirement, all transmission elements included in the primary zone of protection of any generator, transmission line, or transformer shall be considered to be part of the single element testing. Maintenance condition contingency analysis is treated as NERC Category P1 contingencies in that automatic shedding of load is not permitted to maintain facilities within thermal and voltage limits.
- After the outage, the system must be capable of readjustment so that all transmission equipment will be loaded within the seasonal normal ratings and within the normal voltage limits as specified in *Section 4.1*. Readjustment can include the re-dispatch of generation, or switching operations to reconfigure system topology.

6.3.2. Non-BES Transmission Facilities

- There are no NERC, RF, or FE criteria regarding maintenance condition analysis of non-BES facilities.

6.4. Open Ended or Line Restoration Transmission Line Contingency Analysis (NERC Category P2-1)

6.4.1. Open ending (either through the opening of a breaker without a fault or during line restoration) a normally networked or one which could be networked transmission line will not cause adjacent networked transmission facility loadings to exceed applicable ratings, will not cause instability or cascading outages, and will not cause adjacent networked facilities to violate the voltage criteria as specified in *Section 4.1*.

6.4.2. The open ended facility itself may, under peak conditions, experience some combination of; loading beyond STE rating, steady state voltages less than or voltage deviations greater than those specified in *Section 4.1* and may require some level of local load to be shed for a limited time period in order to meet planning criteria.

- This potential loss of load is acceptable if the loss of load risk is less than 100 hours per year and the amount of load at risk is less than that detailed in *Section 11, Loss of Load Criteria*.

6.5. **Maximum Credible Disturbance (MCD)/ Extreme Contingency Testing (NERC Extreme Events) - Facilities >200kV**

6.5.1. FE facilities >200kV shall be tested to determine the effects of various types of severe contingencies on system performance, including voltage and angular stability. (The 200kV cutoff level was selected based on engineering judgment that MCD events at lower voltages would not have a widespread impact on the BES.) These tests are performed as a means to study the system for its ability to withstand disturbances beyond those, which would reasonably be expected.

6.5.2. Examples of these less probable contingencies to be studied include:

- Loss of a single generator, transmission circuit, single pole of a bipolar DC line, shunt device, or transformer followed by the loss of another single generator, transmission circuit, single pole of a bipolar DC line, shunt device, or transformer prior to system readjustments between outages
- Local area events affecting the transmission System such as:
  - Sudden loss of the entire generation capability of any station for any reason
  - Sudden loss of all lines on a single right-of-way
  - Sudden loss of a tower line with three or more circuits
  - Sudden loss of all lines and transformers of one voltage emanating from a substation or switching station
  - Sudden dropping of a large load or major load center
- Wide area events affecting the transmission System, including loss of two generating stations resulting from conditions such as:
  - Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation
  - Loss of the use of a large body of water as the cooling source for generation
  - Wildfires
  - Severe weather (e.g., hurricanes, tornadoes, etc.)
  - A successful cyber attack
  - Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants
- Failure of a fully redundant special protection system to operate when required
- Operation, partial operation, or misoperation of a fully redundant special protection system for an event or condition for which it was not intended to operate

6.5.3. In the event these tests indicate potential for a cascading outage, an evaluation shall be conducted to consider such things as:

- Consequences to the FE and adjacent systems of such a disturbance
- General scope of a capital project(s) to correct the condition
- Operating steps which would be required to minimize the severity of the disturbance

6.5.4. Based on this evaluation, a decision will be made as to whether a capital project should be considered to mitigate the potential risk.

- One option that should be considered to mitigate these situations is the installation of UVLS or other special protection schemes.

7. Voltage Stability Requirements

7.1. The FE transmission system will be developed such that it can be operated at the expected peak and at lower load levels such that the system will maintain voltage stability with a single generating unit or a specified transformer, transmission line, or reactive device (capacitor, static VAR compensator, synchronous condenser, etc.) out of service as a pre-existing system condition followed by the loss of another single transmission system element.

7.2. PV analysis shall be used as the method of testing voltage stability.

7.2.1. This analysis shall be performed using a system model with an initial load equal to the 50/50 load forecast for the area under study.

7.2.2. System load will be incremented at a 0.85 power factor while simulating the contingency and then recording voltages at select transmission buses.

7.2.3. The process of incrementing load, simulating the contingency and recording voltages is repeated until the power flow will no longer converge.

7.2.4. In order for the system to be considered stable, the load in the area under study must be able to be incremented beyond the 90/10 forecasted peak prior to any voltage instability as indicated by the slope of the PV curve or by the power flow case failing to converge.

7.3. While not a requirement for voltage stability testing, the system may also be evaluated for the most severe combination of two generating units plus a single transmission element out of service and for the most severe combination of one generating unit plus two transmission elements out of service.

7.3.1. Based on this evaluation, operating parameters such as area reactive reserve requirements can be developed.

7.3.2. Additionally, a determination can be made as to whether a project should be considered to mitigate the potential risk including the installation of UVLS or other special control schemes.

8. System Transient Stability

The FE transmission system will be developed such that it can be operated at the expected peak and at light load levels in compliance with the following criteria:

8.1. **Single Element Stability Analysis (NERC Category P1)**

8.1.1. The loss of any single generating unit, transmission line, transformer, or shunt device without a fault.

8.1.2. The loss of any single generating unit, transmission line, transformer, or shunt device as a result of a single line-to-ground or three-phase fault with normal clearing.

8.1.3. Loss of a single pole of a bi-polar DC line.

8.1.4. Criteria

- All generating units in the system must maintain transient stability during and after the contingency. A generating unit is considered to be stable if the machine rotor angle and speed curves are well damped by the end of a 15-second simulation.
- The contingency must not cause system instability or cascading outages.
- Selected system voltages and system frequency shall be monitored as part of observing system stability.
- For these single element outages, it is not acceptable to trip a unit or units to maintain system stability.

8.2. **Subsequent Contingency Stability Analysis (NERC Category P3 & P6)**

8.2.1. The subsequent contingency is defined as the occurrence of any of the events listed in *Section 8.1,* followed by manual system adjustments and a second event from *Section 8.1*.

8.2.2. Criteria

- The contingency must not cause system instability or cascading outages.
- For these multi-element outages, it is acceptable to trip a local unit or units to maintain system stability, but all other generating units in the system must maintain transient stability during and after the contingency. A generating unit is considered to be stable if the machine rotor angle and speed curves are well damped by the end of a 15-second simulation.
  - Tripping of units to maintain system stability must be accomplished via local protective relays. Remote tripping to maintain stability is not permissible.
  - Reducing stuck breaker and/or backup clearing times to provide adequate margin for relay coordination will be evaluated before any unit tripping is accepted.
  - The choice of stability corrective measures such as faster relaying, independent pole operation of breakers, additional transmission, restricted unit output or unit tripping must be made on an individual case basis after considering, probability of occurrence, severity of disturbance, and economics.
- Selected system voltages and system frequency shall be monitored as part of observing system stability.

8.3. **Multiple Element Outage Stability Analysis (NERC Category P4, P5, & P7)**

8.3.1. Loss of any bus section as a result of a single phase fault with normal clearing.

8.3.2. Loss of a breaker as a result of an internal single phase fault with normal clearing.

8.3.3. Loss of a generator, transmission line, transformer, or bus section as a result of a single phase fault with delayed clearing (stuck breaker or protection system failure).

8.3.4. Criteria

- The contingency must not cause system instability or cascading outages.
- For these multi-element outages, it is acceptable to trip a local unit or units to maintain system stability, but all other generating units in the system must maintain transient stability during and after the contingency. A generating unit is considered to be stable if the machine rotor angle and speed curves are well damped by the end of a 15-second simulation.
  - Tripping of units to maintain system stability must be accomplished via local protective relays. Remote tripping to maintain stability is not permissible.
  - Reducing stuck breaker and/or backup clearing times to provide adequate margin for relay coordination will be evaluated before any unit tripping is accepted.
  - The choice of stability corrective measures such as faster relaying, independent pole operation of breakers, additional transmission, restricted unit output or unit tripping must be made on an individual case basis after considering, probability of occurrence, severity of disturbance, and economics.
- Selected system voltages and system frequency shall be monitored as part of observing system stability.

9. Reactive Power Requirements

9.1. Requirements at Transmission System Load Delivery Points

9.1.1. The power factor of the load reflected to the transmission system should be maintained as close to unity as possible.

9.1.2. The minimum requirement for connected load is that the power factor is between 0.97 lagging to 0.99 leading.

9.1.3. Refer to *TPP-REF-004 Requirements for Transmission Connected Facilities* for more details regarding this requirement.

9.2. Requirements on the Transmission System

9.2.1. The need for supplemental voltage support and the need to accommodate the import, export, and transfer of power primarily determine the need for additional reactive compensation installed on the transmission system.

- The requirements of the transmission system are based on the assumption that the delivery points are meeting the above stated requirement.

9.2.2. Where practical and economically justifiable, the reactive power losses on the transmission system should be supplied by reactive resources on the transmission system.

10. Cascade Analysis

10.1. Cascade analysis shall be performed for all NERC scenarios including Extreme Event scenarios that result in a transmission line or transformer loading beyond 125% and for any scenario resulting in a transmission <100 kV line or transformer loading beyond 125% of appropriate seasonal rating.

- *The 125% level is selected as a proxy for the point where a protective relay may operate as the result of an overload.*
- *The potential for a cascading outage is determined using the steady state power flow model and the following method.*
- *After simulation of a contingency, facilities meeting the following criteria are removed from service and the case is resolved.*

10.1.1. Facilities loaded to 125% or greater of the seasonal short term emergency rating for the first case solution immediately following the contingency and 100% or greater than summer short term emergency for subsequent case solutions.

10.1.2. Generators with terminal voltages below their minimum operating voltage. These voltages provided by the individual plant owners for each unit.

- If no information has been provided by a plant owner, then Vmin is assumed to be 95%.

10.1.3. The process is repeated until either the case fails to converge indicating the potential for a system collapse or until neither of the two criteria above are violated, indicating an ultimately stable system.

10.1.4. This process is limited to three successive passes after which it is assumed that there is a potential for system collapse.

10.1.5. In the event that this steady state analysis indicates a possible collapse, additional analysis is performed using dynamic analysis for verification.

10.2. Automatic and/or manual load shedding up to the limits detailed in *Section 11, Loss of Load Criteria*, are permitted to prevent a system cascade.

10.2.1. If load shedding beyond these values are required to prevent a system cascade, then system reinforcements or modifications needed to limit load shedding to values below those described in *Section 11, Loss of Load Criteria*, will be developed and implemented.

10.3. The contingencies that indicate the possibility of a system cascade using the above method will be identified as and will be communicated to both the appropriate Control Center and PJM.

11. Loss of Load Criteria

11.1. **Uncontrolled Load Loss** – Loss of load that is unplanned or unexpected caused by voltage collapse on the BES system and/or cascading thermal overload/tripping of BES facilities, is unacceptable under any NERC category P1 through P7 contingency conditions.

11.2. **Planned Loss of Load** – Comprises the following two components:

11.2.1. **Consequential Loss of Load** – The result of the topology of the transmission system. In other words, the outage of a particular line or transformer results in the loss of load directly served by that facility. One example is the loss of a transmission line that has a mod substation tapped to it.

11.2.2. **Automatic Loss of Load** – The result of a control scheme that is intended to shed load that would not otherwise be lost as the result of an outage of a transmission element. For purposes of this document, automatic loss of load refers only to those schemes that directly shed load as a result of a change in system topology (such as a transfer trip scheme) and not to those schemes that shed load as a result of a change in a measured system quantity (such as a UVLS scheme).

11.3. With the exception of the JCP&L 34.5 kV system, the FE system will be planned and constructed such that, for any NERC Category P1 through P7 event, the associated loss of load will be limited to <300 MW.

11.4. Due to specific requirements of the New Jersey BPU, the JCP&L 34.5 kV system will be planned and constructed such that for any NERC Category P1 event, the associated loss of load will be limited to <12,500 customers and <50 MW.

12. Breaker Interrupting Capability

12.1. The fault duty that must be interrupted by any breaker will not exceed 100% of the circuit breaker capability. The determination of the breaker's capability for any specific fault will be done in full accordance with the C37.010-1999 (R2005) standard for symmetrical current rated breakers and with the C37.5-1979 standard for total current rated breakers.

12.2. The following assumptions/conditions shall be included in the breaker evaluation:

12.2.1. Fault duty will be determined with all generation in service.

12.2.2. The pre-fault voltage shall be one per unit, unless sufficient reason exists to use a higher value – for example, proximity to a generator, or when using a voltage from a load flow calculated voltage profile.

12.2.3. Breakers shall be evaluated with the system in its normally operated state (i.e., normally-open switches open and normally-closed switches closed). Additional cases shall be run closing normally open points that may be closed during the course of normal operations

12.2.4. The number of transformations away from generation shall be two, unless sufficient reason exists to use one.

12.2.5. Breakers using oil or air magnetic interruption shall be derated for automatic reclosing. Gas, vacuum and air blast shall not. Using the actual reclosing sequence is preferred. However, instantaneous reclosing may also be assumed.

12.2.6. No additional derate factor shall be used.

12.2.7. Subtransient reactances shall be used for all synchronous generators.

12.2.8. For non-synchronous machines, equivalent impedances shall be obtained from the generator owner.

12.2.9. Close and latch ratings shall be evaluated, and assumed to be 2.6 times rated, per the appropriate standard

12.2.10. Both three phase and single-line-to-ground faults shall be evaluated.

12.2.11. Ring bus breakers shall be evaluated based on total bus fault current.

13. Airbreak Switch Capability

13.1. Loop Interrupting Requirements

13.1.1. A switch's loop interrupting capability is a rating given to a switch for its opening capability in a closed loop (networked) system and is dependent on its available Reach-of-Arc (ROA), the system loop impedance at that point, and the operating voltage.

- The ROA is the distance from the switch's live parts to the nearest electrically conducting object during the switch opening process.
- *Table 3: Standard Design Reach of Arc* specifies the standard design ROA for switches operated at different voltages.
- Airbreak switches used for loop splitting at voltages >200 kV require the use of SF6 interrupters; no ROA requirements are provided for switches at these voltage levels.

Table 3: Standard Design Reach of Arc

Line Voltage (kV)	ROA (ft)
230	N/A – SF6 Interrupter required
115/138	9.0
69	5.0
46	5.0
≤34.5	4.5

13.1.2. Each switch is evaluated to ensure that it is capable of interrupting the current that would normally flow through it during loop interrupting operations and this information is provided to system operators.

- If necessary, a supplemental interrupting device such as vacuum bottles can be added to a switch.
- In no case shall a switch be operated if measured flow through the switch exceeds its evaluated interrupting capability.

13.2. **Line Dropping Requirements**

13.2.1. The capacitive line charging current that a switch may safely interrupt shall be limited to a maximum of 4 amps.

13.2.2. Beyond this limit, a supplemental quick-break interrupting device is required.

13.2.3. *Table 4: Line Dropping Limits* shows the maximum length of line that can be dropped using switches without a supplemental quick-break device.

- Switches with vacuum bottles should not be used to drop line charging current unless the vacuum bottles are protected by metal oxide varistor (MOV) or other voltage limiter to limit voltage across the bottle contacts to below its design specifications.
- Airbreak switches are not currently used for line dropping at voltages >200 kV so no requirements are provided for switches at these voltage levels.

Table 4: Line Dropping Limits

Line Voltage (kV)	Line Length (mi.)
115/138	9.0
69	15.0
46	30.0
34.5	38.0
25	55.0
23	60.0

14. Facility Connection Requirements

14.1. Detailed facility connection requirements are discussed in *TPP-REF-004 Requirements for Transmission Connected Facilities*.

14.2. This document includes requirements regarding system protection, acceptable connection configurations, reactive power and power quality requirements such as voltage flicker and harmonics.

Appendix A – Summary of Planning Criteria

Facility	Contingency Type	Loading Limits	Load Shed Allowed	Restore to Rating Following Event
PJM BES Facilities	Category P1	STE	No	Normal
	Category P3 & P6	STE	Auto Only *	Not Required
	Other Category P2, P4, P5 & P7	STE	Auto Only *	Not Required
	Maintenance Conditions	STE	No	Normal
All Other Facilities	Category P1	STE	No	Not Required
	Category P3 & P6	N/A	N/A	N/A
	Other Category P2, P4, P5 & P7	N/A	N/A	N/A
	Maintenance Conditions	N/A	N/A	N/A

* In situations where the outage results in a pocket of load being served radially by a single ≥100 kV facility, manual load shedding, up to the limits detailed in *Section 11 Loss of Load Criteria*, is permitted to maintain facilities within thermal and voltage limits.

Related Documents

Title
Circuit Loadability Guide and Rating Methodology (TPP 01)
Transformer Loadability Guide and Rating Methodology (TPP 02)
TPP-REF-004 Requirements for Transmission Connected Facilities
Transmission System Protection Practices (TPP 05)

Revision History

All revisions of this document are reviewed and approved by the applicable Manager(s) and by the Director, Transmission Planning and Protection. The revision process is described below:

1. Revisions/clarifications are determined as major or minor by Director, Transmission Planning and Protection.
2. Document changes are maintained in a redline version.
3. Dates, author(s), type, and description, for revision are recorded in Revision History.

Rev.	Date Revision Started	Revision Effective Date	Name	Review / Revision Comments
1		1/21/2007	JCStephens	Minor: Revised Section 9 so that cascade analysis methods is consistent with MISO methodology and to provide guidance in determining IROLs.
2		2/12/2008	JCStephens	Major: Periodic review and update.
3		2/19/2010	JCStephens, CDPeretti	Major: Periodic review and updates to sections listed below: • Ratings Used in Power Flow Models - New section which makes the ratings used for criteria testing consistent across FE. • Steady State Voltage Level Limits - Added statement that we'll contact Nuke plants if we see violations to show compliance with NUC-001. Also revised the TMI low voltage limits. • Voltage Change as a Result of Capacitor Switching - Added requirement to make sure, that with the strongest line out at a station, switching a capacitor doesn't to insure that the steady state voltage change caused by switching the capacitor does not exceed the bandwidth of the capacitor automatic voltage control. • Fast Switched Capacitor Voltage Criteria - Added option to allow use fast switched capacitors in certain conditions. • Solution Parameters Used in Planning Studies - Specifically spelled out the solution parameters used in the analysis. Primarily to assure compliance with PJM methods. • Thermal and Voltage Assessment Requirements - Cleaned up the distinction between "PJM Criteria" facilities and all other facilities. Used to distinguish between facilities on the PJM monitored list and those not on that list. Now the distinction is between PJM BES, MISO BES, and (for Cat >B) Non-BES facilities. • Single Contingency (NERC Category B) - Modified the requirement all facilities except the PJM BES facilities such that, if the faulted element can be cleared up and the line restored within 5 minutes, the criteria would be against the STE rating instead of the presently used LTE rating. • Subsequent Contingency (NERC Category C3) - Definitively stated that for the PJM BES facilities subject to a Cat C3 contingency that if after the second event, a pocket of load is being served by a single BES line, that load shedding up to 300MW is allowed to get below STE • Multiple Element Outage (NERC Category C) - Definitively stated that for the PJM BES facilities subject to a Cat C contingency that if after the second event, a pocket of load is being served by a single BES line, that load shedding up to 300MW is allowed to get below STE.

Rev.	Date Revision Started	Revision Effective Date	Name	Review / Revision Comments
				• Subsequent Contingency (NERC Category C3), Multiple Element Outage (NERC Category C), and Maintenance Condition Contingency Analysis - Specifically stated that Cat C1,2,5, C3, and maintenance condition outages do not apply for facilities less than BES. • Maximum Credible Disturbance (MCD)/ Extreme Contingency Testing - Explicitly stated that Max Credible Contingency (Cat D) criteria applies only to 200kV and above. • Revised cascade test to reflect first tripping at 125% and subsequent tripping at 100%. Also, limited the number of successive trips to 3 before declaring a potential collapse. • Expanded the Breaker Interrupting Capability section to provide details of the assumptions and conditions used to determine breaker interrupting capability.
4		4/22/2010	JCStephens	Minor: • Table 2 - Revised Perry emergency minimum voltage per NPOA which will go into effect 4-1-2010. Also, corrected spelling error in the table. • Section 4.1 - Clarified that EDPP would notify the nuclear plants for Cat A, B, and C contingency criteria violations. • Section 6.2.3.1 - Duplicated the second bullet from Section 6.2.2.1 into this section. This bullet was inadvertently left out of at the time of the last major revision. • Section 6.3.1 - Revised title to include "in PJM".
5		12/6/2010	JCStephens, JT Martinez	Minor: • Section 3.3 – Changed the rating used for Rate 2 of Lines in the "All Other Facilities" column to STE for consistency with other line ratings. Also changed table for all rate 1 to read Normal instead of Continuous • Section 4.1 – Revised 500 kV Emergency Minimum voltage limit from 0.975 to 0.97. • Section 6.2.1.1 – Removed loss of a circuit breaker as one of the testing requirements for Cat B. Cat B criteria applies only to breaker to breaker contingencies. Clarified that for the loss of one end of a networked line, the remaining radial portion of the system meet the non-BES voltage criteria. • Section, 6.2.1.2, 6.3.1, and 6.3.2 – Removed loss of a circuit breaker as one of the testing requirements for Cat B. Cat B criteria applies only to breaker to breaker contingencies. • Section 6.4 – Clarified that 6.4 applies only in for single end condition caused by a breaker outage or during line restoration. Also clarified that it applies to all voltage levels. • Section 8.2.1 – Revised Cat C3 dynamics criteria to be the same as the C1259 criteria. • Section 10 – Changed "RTO" to "MISO" in the last line of the section to clarify that it is not necessary to provide potential IROL results to PJM. • Section 11 – Added BES system and BES facilities to for clarification • Section 13.1 – Added 230 kV and 46 kV switches to Table 3. Also removed 72kV, 36 kV and 22kV voltages classes form table leaving 69 kV, 34.5 kV & 23 kV in Table 3. • Section 13.2 - Removed 72kV, 36 kV and 22kV voltages classes from table leaving 69 kV, 34.5 kV & 23 kV in Table 4. • Appendix A – Revised and simplified definitions • Appendix B – Revised table to align with change in 3.3 All other facilities Cat B to be STE from LTE • Cover Page - Effective date does not reflect actual effective date. Effective date of February 1, 2011 based on signatures applies.
6		6/1/2011	JT Martinez, DP Morrison	Minor: • Section 2 – Updated voltage transmission voltage level to be 100 kV removed. Removed MISO reference.

Rev.	Date Revision Started	Revision Effective Date	Name	Review / Revision Comments
				• Section 3.1 – Added reference to former Allegheny Companies and a time frame for rating transition. • Section 4.1 – Updated Table 1 to include 25 kV. Removed footnote. • Section 4.1 – Updated Table 2 to include Beaver Valley 138 kV limits • Section 5 – Removed reference from PJM/MISO to FE Footprint • Sections 6.2.1.1 & 6.2.1.2, - Removed MISO Reference. Changed Heading for 6.2.1.2. • Sections 6.2.2.2, 6.2.3.2, 6.3.2, - Removed MISO Criteria. • Section 10 – Changed RTO to PJM • Sections 13.1 & 13.2 – Updated tables to include 25 kV & 46 kV • Appendix B – added footnote to the table
7		10/1/2014	JP Syner	Minor: • Updated document signature page to match current organization • Section 4.1 - Removed Table 2 – Nuclear Power Plant Transmission Bus Voltage Limits • Section 6.2.3.2 – Updated to include language around specific state agency criteria. • Section 7 – Updated to include additional transmission elements in addition to generators and lines.
8		12/1/2016	JP Syner	Minor: • Updated document signature page to match current organization • Updated contingency types for new NERC TPL-001-4 standards
9	9/16/2019	11/5/2019	J. C. Fraley, J. Giordano, L. Hozempa, and G. Marchewka	Minor: • Created Purpose, Key Terms and Definitions, and Introduction sections from existing content (including content moved from previous Appendix). • Updated formatting and editing per Transmission Operations style.

Approvals

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