Exelon
Transmission Planning Criteria

Applicable to ComEd, PECO, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric and Delmarva Power and Light Company

March 22, 2024

Table of Contents

1 Scope and Objective

The function of the transmission system is to transport power from generating resources to distribution systems in order to serve the demand of the end-use customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions. This document supplements NERC, RF and PJM requirements by providing reliability criteria upon which needs for reinforcements and enhancements are determined to support reliable transmission systems for Exelon and its subsidiaries, Baltimore Gas and Electric Company ("BGE"), Commonwealth Edison Company, including its wholly-owned subsidiary Commonwealth Edison Company of Indiana, Inc. ("ComEd"), PECO Energy Company ("PECO"), Pepco Holdings, Inc. ("PHI"), Potomac Electric Power Company ("Pepco"), Delmarva Power & Light Company ("Delmarva"), and Atlantic City Electric Company ("ACE").

Unless noted otherwise this criteria applies to networked facilities 100kV and above for BGE, ComEd, Pepco, ACE and Delmarva, and networked facilities 69 kV and above for PECO. In addition, if there are contingencies of facilities not included in the description above that are known to impact the reliability of the transmission system then those will be included in this criteria.

2 National and Regional Criteria and Guides

2.1 NERC Transmission Planning Standards

The North American Electric Reliability Corporation was established to promote the reliability of the Bulk Electric System (BES) of North America. NERC coordinates reliability standards for the power systems of the United States, the bordering provinces of Canada, and a portion of Mexico. NERC consists of seven regional reliability organizations. Exelon is a member of the Reliability*First* (RF) Regional Reliability Organization. NERC has developed planning standards to ensure the reliable operation of the interconnected BES. These standards can be found on the NERC web site. Exelon plans the BES to meet the requirements of NERC and RF.

2.2 PJM Planning Standards

Exelon is a member of the PJM Interconnection, LLC (PJM) Regional Transmission Organization (RTO). PJM manages a regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. The criteria PJM uses in developing the RTEP is set forth in PJM Manual 14B. PJM is designated as the Transmission Planner for Exelon companies.

3 Exelon Transmission Planning Adequacy Criteria

3.1 Planning Principles and Standards / Adequacy

The transmission system must perform reliably for a wide range of conditions. Because system operators can exercise only limited direct control, it is essential that studies be made in advance to identify the facilities necessary to assure a reliable transmission system in future years.

The voltages and equipment loadings on the transmission system should be within acceptable limits, both during normal operation and for an appropriate range of potential system faults and equipment outages.

Table 1A and Table 1B specify the conditions analyzed by Exelon for the purpose of identifying any thermal or voltage violations. The 50/50 and 90/10 load forecasts are defined in section 3.2.1.1.

Voltage limits are in reference to the nominal design voltage and shown in per unit (pu). System readjustment is allowed when attempting to reduce line loadings or improve voltage. System readjustments considered in planning analysis include:

- Generation redispatch *
- Phase angle regulator adjustment**
- Capacitor bank switching
- Circuit breaker switching
- Inductor switching

Local practices that reflect Nuclear operating agreements are followed when considering using nuclear generation redispatch as a viable mitigation strategy for those N-1-1 contingencies not involving a generating unit. If allowed, nuclear redispatch can be applied after the loss of the first element to return to normal ratings. The required amount of nuclear generation redispatch should not exceed the maximum output of a single nuclear unit at the site that is required to be reduced. This approach to generation dispatch in response to system events reflects realistic operational constraints associated with nuclear generation and gives consideration to safe operation of the plants.

Table 1A
Exelon West – ComEd Adequacy Criteria

* For redispatch in N-1-1 studies, maximum output limited to installed capacity x (1 – PJM average Effective Equivalent Demand Forced Outage Rate (EEFORd))

** In ComEd, phase angle regulator adjustment is only allowed to relieve loadings in the Chicago Metro Area. The "Chicago Metro Area" is defined as consisting of all facilities inside Chicago or feeding Chicago load from the 345 kV or 138 kV systems. This includes the autotransformers at Skokie, Des Plaines, Elmhurst, McCook, Bedford Park, and State Line, as well as the 138 kV lines feeding from these stations toward the Chicago Metro Area. The radial 345 kV lines that tie to these autos are also considered to be Chicago Metro Area Facilities. The phase angle regulators were installed on the ComEd system to control flows on Chicago Metro Area Facilities, and using them to relieve loadings outside of the Chicago Metro Area puts undue stress and risk on the Chicago Metro Area transmission system.

Outage Event	Thermal 50/50 Load Forecast	Thermal 90/10 Load Forecast	Voltage (pu) (50/50 and 90/10 load)
None	All Facilities Within Normal Ratings	All Facilities Within Long-Term Emergency Ratings (4)	0.95 min (5) 1.05 max
1 Line or 1 Transformer or 1 Generator or 1 Capacitor Bank or Shunt Inductor	All Facilities Within Normal Ratings (1)	All Facilities Within Long-Term Emergency Ratings (2)	0.92 min (5) 1.05 max
1 Open line section without a fault that results in load served from only one end of a normally networked transmission line	All Facilities Within Long-Term Emergency Ratings (2)	All Facilities Within Long-Term Emergency Ratings (2)	0.92 min (5) 1.05 max
One Line, Transformer, Generator, Capacitor Bank, or Shunt Inductor, manual system adjustments, followed by another Line, Transformer, Generator, Capacitor Bank, or Shunt Inductor	1st Contingency: All Facilities Within Normal Ratings (1) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings(2)	Not required	0.92 min (5) 1.05 max (9)
1 Underground Line, manual system adjustments, followed by another Underground Line, Chicago Central Business District only	1st Contingency: All Facilities Within Normal Ratings (1) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings (2)	1st Contingency: All Facilities Within Long-Term Emergency Ratings (2) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings(2)	0.92 min (5) 1.05 max
1 Faulted Bus Section (345 kV or above) or 1 Faulted non-Bus Tie Circuit Breaker (8) (345 kV or above)	All Facilities Within Long-Term Emergency Ratings (2)	Not required	0.92 min (5) 1.05 max (9)
2 Lines on a Common Tower (7) (simultaneous, all voltages) or 1 Faulted non-Bus Tie Circuit Breaker (8) (138 kV) or 1 Faulted Bus Tie Circuit Breaker (8) (all voltages) or 1 Faulted Bus Section (138 kV)	All Facilities Within Cascading Levels (3) (6)	Not required	0.92 min (5) 1.05 max (9)

(1) Can go up to short-term emergency ratings, but must return to normal ratings post contingency, load shed not allowed
(2) Can go up to short-term emergency ratings, but must return to long-term emergency ratings post contingency, load shed not allowed
(3) Must return to long-term emergency ratings post contingency, planned/controlled load shed allowed
(4) The 90/10 load forecast is higher than the expected 50/50 load forecast, thus equipment loading up to emergency ratings is acceptable for normal conditions
(5) 0.98 at legacy nuclear generating stations with one or more units on-line or with all units off-line
0.98 at legacy coal, combined cycle, combustion turbine generating stations with one or more units on-line
0.98 at legacy coal, combined cycle, combustion turbine generating station with all units off-line and plant auxiliaries supplied from unregulated* power sources
0.95 at legacy coal, combined cycle, combustion turbine generating station with all units off-line and plant auxiliaries supplied from regulated** power sources
(6) As a proxy for cascading, ComEd uses the lower of the relay loadability rating or 115% of the load dump rating
(7) Excludes lines that share a common structure for 1 mile or less
(8) For Planning Criteria purposes a “bus tie circuit breaker” normally trips only for bus faults. A breaker that normally trips for line or transformer faults is considered a line or transformer breaker, even if it has “Bus Tie” in the breaker name.
(9) 50/50 load only

*unregulated = Plant auxiliary power source not equipped with load tap changers
** regulated = Plant auxiliary power source equipped with load tap changers
Note: For contingency analysis, a synchronous condenser is treated the same as a line.
Note: Wind Turbines are to meet the same voltage requirements as Transmission Substations.

Table 1B

Exelon East - ACE, Delmarva, PECO, BGE, Pepco Adequacy Criteria

Outage Event	**Thermal (50/50 Load Forecast)**	**Thermal (90/10 Load Forecast)**	**Voltage (pu) 230 kV or below (50/50 and 90/10 load)**	**Voltage (pu) 500 kV (50/50 and 90/10 load)**
None	All Facilities Within Normal Ratings	All Facilities Within Long-Term Emergency Ratings (3)	0.95 min 1.05 max	1.00 min 1.10 max
1 Line or 1 Transformer or 1 Generator or 1 Capacitor Bank or Shunt Inductor	All Facilities Within Normal Ratings (1)	All Facilities Within Long-Term Emergency Ratings (2)	0.92 min 1.05 max	0.97 min 1.10 max
1 Open line section without a fault that results in load served from only one end of a normally networked transmission line	All Facilities Within Long-Term Emergency Ratings (2)	All Facilities Within Long-Term Emergency Ratings (2)	0.92 min 1.05 max	0.97 min 1.10 max
One Line, Transformer, Generator, Capacitor Bank, or Shunt Inductor, manual system adjustments, followed by another Line, Transformer, Generator, Capacitor Bank, or Shunt Inductor	1st Contingency: All Facilities Within Normal Ratings (1) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings (2)	Not required	0.92 min 1.05 max (5)	0.97 min 1.10 max (5)
1 Underground Line, manual system adjustments, followed by another Underground Line, in the Baltimore, Philadelphia and Washington DC Central Business Districts only	1st Contingency: All Facilities Within Normal Ratings (1) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings (2)	1st Contingency: All Facilities Within Long-Term Emergency Ratings (2) 2nd Contingency: All Facilities Within Long-Term Emergency Ratings (2)	0.92 min 1.05 max	0.97 min 1.10 max
1 Faulted Bus Section or 1 Faulted Circuit Breaker or 2 Lines on a Common Tower (4)	All Facilities Within Long-Term Emergency Ratings (2)	Not required	0.92 min 1.05 max (5)	0.97 min 1.10 max (5)

(1) Can initially go up to short-term emergency ratings for PAR controlled facilities or long-term emergency for all others. Must return to normal ratings post contingency through system readjustments
(2) Can initially go up to short-term emergency ratings for PAR controlled facilities, but must return to long-term emergency ratings post contingency through PAR adjustment
(3) The 90/10 load forecast is higher than the expected 50/50 load forecast, thus equipment loading up to emergency ratings is acceptable for normal conditions
(4) Excludes lines that share a common structure for 1 mile or less
(5) 50/50 load only

Minimum Normal and Emergency Voltage Limits at Legacy Generating Stations

Plant auxiliary power equipment requires adequate voltages in order to maintain reliable operation of on-line generators as well as to provide for reliable start-up capability for off-line generators. In general, the Exelon systems are designed to adhere to PJM voltage limits. There are exceptions to this practice, however, in cases where there are existing legacy designs and agreements. These exceptions are: Voltage limits at legacy nuclear generating stations (including offsite power sources) may be governed by existing Nuclear Plant Interface Requirements (NPIRs). ComEd nuclear, coal, and gas generators in service prior to 3/25/19 are maintained to the voltage limits indicated in Table 1A, note 5.

3.2 Detailed Adequacy Criteria

3.2.1 System Load Level

3.2.1.1 Peak Period Studies

The peak load period must be studied to determine future requirements for the transmission system. The forecast for system peak load to be used in studies for future years under this criteria are provided by the PJM Load Analysis Subcommittee and are the 90/10 and 50/50 forecasts. A '50/50' load forecast provides a peak load projection that has an equal probability of being higher or lower than the peak load that actually occurs in that year. A '90/10' forecast provides a peak load projection with a 10% probability that the actual peak will be higher than the level forecasted in that year. A system planned using the '90/10' forecast provides additional security, as the load estimate is usually about 7% higher than the '50/50' forecast.

For summer peak period studies, on-shore wind generation is not dispatched. Analysis shows that on summer peak days there is often little significant wind blowing, therefore we cannot depend on on-shore wind generation to offload the Transmission system during these conditions.

3.2.2 Circuit Breaker Interrupting Capability

Under normal conditions, the fault current through a circuit breaker shall not exceed the maximum nameplate rating of that breaker. Further, a circuit breaker shall have sufficient capability to interrupt a close-in single-phase or three-phase to ground fault.

4 <u>Transmission Planning Security Criteria</u>

4.1 Transmission Voltage Stability

4.1.1 General

Voltage stability is defined as the ability of the power system to maintain steady and acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance.

4.1.2 System Representation

Generation dispatch and reactive capability should be modeled consistent with RTO practice. The system load model should be a reasonable representation of the magnitude and characteristics of the real and reactive loads on the system at peak periods or loads where voltage instability is most likely to occur. The expected transmission system configuration, including reinforcements and other material changes, should represent the time period under study.

4.1.3 Determination of Stability

Table 2 summarizes voltage stability criteria including a description of the contingency, the NERC TPL Standard event category, the type of fault and the applicable threshold load level. Mitigation is required for any violations.

Voltage stability margin is defined as the difference between total system load (including losses) at the maximum power transfer point and the threshold load level, as presented in Table 2. Voltage stability criteria are satisfied when simulation results demonstrate that voltage stability margin is greater than zero and sufficient voltage levels are maintained at the threshold load level for the scenarios specified per Table 2.

Static reactive capability should be sufficient to ensure that the transmission system can be operated within applicable steady state voltage limits for appropriate contingencies.

Dynamic reactive capability should be sufficient to ensure that the transmission system can transition to a stable steady-state operating point following a disturbance, and to satisfy requirements for Dynamic Voltage Recovery.

Table 2 – Transmission Facility Voltage Stability Criteria

Outage Event	NERC TPL Category*	Threshold Load Level
None	P0	90/10 forecast +3.5%
Loss of a Generator	P1-1	90/10 forecast +3.0%
Loss of a Transmission Element **	P1-2 through P1-5	90/10 forecast +3.0%
Loss of a Generator followed by Loss of another Generator	P3-1	90/10 forecast
Loss of a Generator followed by Loss of a Transmission Element	P3-2 through P3-5	90/10 forecast
Loss of Double Circuit Tower Line	P7	50/50 forecast
Loss of a Transmission Element followed by Loss of a Transmission Element	P6	50/50 forecast
Loss of a Bus Section	P2-2	50/50 forecast
Fault on a Transmission Element w/Delayed Clearing	P4, P5	50/50 forecast
Fault on a Circuit Breaker	P2-3, P2-4	50/50 forecast

* NERC TPL-001-4 Standard Steady State & Stability Performance Extreme Event contingencies are only studied to evaluate their impact on the system. No mitigation is required.

** Lines, transformers, and shunt devices are considered transmission elements.

4.2 Dynamic Voltage Recovery (Exelon West – ComEd only)

4.2.1 Background

When a fault occurs on the transmission system, voltages are momentarily reduced. Once the fault is cleared, system voltages follow a transient Dynamic Voltage Recovery (DVR) trajectory as they recover to steady state conditions.

4.2.2 System Representation

DVR is evaluated using a dynamic model of the system capable of simulating the transient response of transmission system voltages, loads, and generators in the initial seconds following a fault on the transmission system.

In addition to dynamic resources, transient voltages will also be influenced by factors that impact steady-state voltages. In particular, it is important to accurately model any sources of reactive power expected to be in service during the event.

The DVR criteria is intended to mitigate the impacts of fault-induced delayed voltage recovery (FIDVR) on the transmission system. Small motors, such as those that drive air conditioner compressors, are the primary contributors to FIDVR because they tend to stall during low voltages. Loads are to be modeled using dynamic models representative of the load mix at each substation. The generic ZIP model is unacceptable as a load model for DVR studies.

4.2.3 Criteria

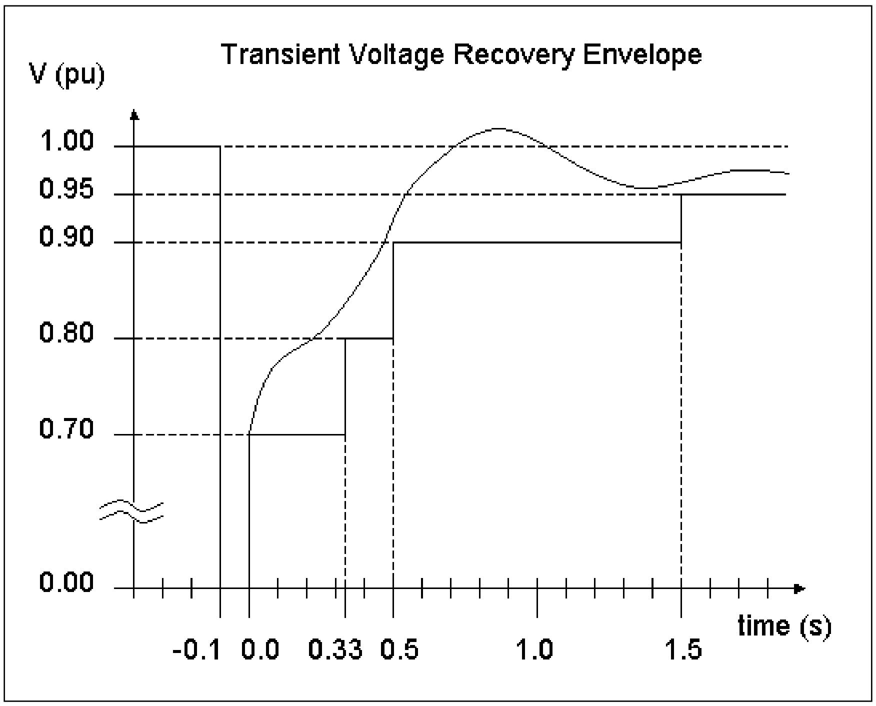
The DVR criteria should be satisfied at BES and high-voltage distribution buses with the exception of generation auxiliary load buses and points-of-interconnection at peak load, given all transmission elements are in 'normal' configuration preceding the event.

Auxiliary loads at generating stations are not contributors to FIDVR. The voltages at generation buses and points-of-interconnection should not be used to determine whether or not the DVR criteria is violated.

Low voltages on a small number of buses do not indicate an event that is significant to the transmission system even if stalling occurs. Violations of the recovery envelope must occur at 10 or more applicable buses before mitigation should be considered. The number of violations and the magnitudes of the violations should be considered when determining if mitigation is necessary.

Following a three-phase fault on the transmission system that results in loss of a single generator or transmission element, the transmission system DVR must conform to the recovery 'envelope' described below, and illustrated in the figure that follows.

1. Following the successful clearing of a fault (normal clearing = 6 cycles), the voltage magnitudes should be no less than 70% of their nominal values.
2. Within 20 cycles following the clearing of a fault, the voltage magnitudes should be no less than 80% of their nominal values.
3. Within 0.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than 90% of their nominal values.
4. Within 1.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than the steady-state voltage minimum, typically 92-95% of nominal.



4.2.4 Mitigation of DVR Violations

Violation of the DVR criteria can increase the potential for severe voltage problems following a fault and should be mitigated with appropriate reinforcements.

4.3 Generator Rotor Angular Stability (Exelon West – ComEd Only)

4.3.1 System Representation

In simulating transmission system disturbances, the following assumptions are made when setting up the study conditions:

- The generators at the plant under study are assumed to be operated at full power output.
- Voltage at the plant under study may be assumed to be regulated to the minimum of the allowable voltage range.

- Other effects, such as power interchange with other companies, changes in nearby generator dispatch and system load level, are considered on a case-by-case basis to the extent that they affect system stability.

4.3.2 Studied Contingencies

The following events are studied:

- A three-phase fault on any transmission or generation element with normal clearing.
- A three-phase fault on any transmission or generation element with delayed clearing due to a stuck breaker or other protective equipment failure. For situations involving independent pole operated breakers, it is assumed that only one phase of the breaker fails to open and the delayed clearing time is used for the remaining single-phase fault.
- A three-phase fault on all transmission lines on a multiple circuit tower with normal clearing.
- A three-phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element.

A one-cycle margin is included in all primary-clearing times to account for simulation uncertainty. This margin should be applied as follows:

- For faults cleared in primary time, it is required that the system remain stable for fault clearing times that include the one-cycle planning margin.
- For faults cleared in delayed time, the one-cycle margin is applied to the time duration of the primary clearing portion of the fault only. No margin is added to the delayed-clearing portion of the fault, i.e., the Total Clearing Time of the fault is not increased.

4.3.3 Fault Clearing Times

Fault clearing times are determined by the associated circuit breakers and protective relays for faults cleared in primary or backup time. The combined operating time, from the moment the fault is applied until the time at which the fault is cleared, is defined as the Total Clearing Time (TCT).

4.3.4 Determination of Stability

A generator is deemed unstable if studies show that it will pull out of synchronism with the system. In cases where a generator does not pull out of synchronism, an acceptably stable situation also requires evidence of adequate damping behavior for all modes of oscillations. For swings characterized by a single dominant mode of oscillation, the damping can be calculated directly from the oscillation envelope. A 15% decrement between swing cycles is suggested, but engineering analysis will determine whether subsequent angular swings on a particular generator are a concern. For swings characterized by multiple modes of oscillations, a small signal stability analysis can be performed and a damping ratio of 0.03 is suggested.

4.3.5 Applicability of Exelon Transmission Planning Angular Stability Criteria:

(1) Exelon criteria shall be applied to all Exelon owned substations and generators connected to Exelon owned substations.

(2) Non-Exelon substations and Generators connected to non-Exelon substations shall be evaluated to the stability criteria required by applicable NERC TPL Standards.