

**EXELON
TRANSMISSION PLANNING
CRITERIA**

Transmission Planning Department

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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 provides approved reliability standards and criteria upon which the needs for reinforcements and enhancements to the Exelon transmission systems are determined. Separate criteria for planning distribution substations are developed and maintained by the Capacity Planning Department. Also not included in this document are specific criteria for specifying generation resource requirements.

“Transmission system” refers to voltage levels that include networked 138, 345, and 765 kV for the ComEd system and 69, 138, 230, and 500 kV for the PECO system. A transmission line serving only distribution facilities at the receiving end is considered to be part of the distribution system and therefore not required to meet the criteria in this document.

Exelon’s transmission planning criteria ensures compliance with the transmission planning standards of the North American Electric Reliability Corporation (NERC) and those of the ReliabilityFirst Corporation (RFC), one of the eight regional reliability organizations (RRO) of NERC.

2. National and Regional Criteria and Guides

2.1 NERC Planning Standards

The North American Electric Reliability Corporation was established to promote the reliability of the bulk electric systems of North America. NERC coordinates reliability standards for the power systems of the United States and the bordering provinces of Canada. NERC consists of eight regional reliability organizations. Exelon is a member of the ReliabilityFirst Regional Reliability Organization. NERC has developed planning standards to ensure the reliable operation of the interconnected bulk electric systems. These standards can be found at the NERC homepage.

The Exelon Transmission Planning Criteria provides a description of how Exelon performs analyses to determine the ability of the interconnected transmission system to withstand probable and extreme contingencies. The analyses are performed by simulated testing of the transmission system as prescribed by NERC.

2.2 Regional Reliability Planning Standards

Exelon is a member of the ReliabilityFirst Corporation, one of the eight regional reliability organizations of NERC. Both ComEd and PECO plan the bulk electric system (BES) to meet the requirements of NERC and RFC. PECO’s 69kV facilities are considered non-BES, and designed to meet a criteria developed specifically for reliable operation of local facilities.

2.3 PJM Planning Standards

Exelon is a member of the PJM Interconnection 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.

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. The more probable contingency conditions should not result in voltages or equipment loadings beyond emergency limits. These 'emergency limits' can vary based on equipment type and allowable time period.

Table 1A specifies outage events that are analyzed by ComEd at the 50/50 and 90/10 load forecasts to determine if any thermal or voltage violations exist. Table 1B specifies outage events that are analyzed by PECO at the 50/50 load forecast.

The differences in load levels employed by ComEd and PECO are dictated by previous regional and historic planning practices. The 50/50 and 90/10 load forecasts are defined in section 3.2.1.1. Thermal capability is given with equipment ratings in amps or MVA. Voltage limits are in reference to the nominal design voltage. Adherence to the criteria given in these tables ensures that Exelon's transmission system meets the applicable reliability requirements of NERC, RFC, PJM, and Exelon.

System readjustment is allowed when attempting to reduce line loadings or improve voltage profile. System readjustments considered in planning analysis include:

- Generation redispatch
- Phase angle regulator adjustment^{*}
- Load tap changer adjustment
- Capacitor bank switching
- Circuit breaker switching
- Inductor switching

Loadings on PECO transmission facilities over their normal rating, following a contingency, must be adjusted back down to normal rating within the time frame of the long term emergency rating. Any of the above listed system readjustments are allowable in this situation as PECO employs 4-hour long-term emergency ratings on transmission equipment, which allows sufficient time to implement any adjustments that reduce loadings to the normal rating.

Loadings on ComEd facilities over their long-term emergency ratings, following a contingency, must be adjusted back down to the long-term emergency rating within the time frame of the short-term emergency rating using the system readjustments listed above.

Nuclear generation redispatch will only be considered as a viable mitigation strategy for non-simultaneous NERC category C contingencies for PECO and only those non-simultaneous NERC category C contingencies not involving a generating unit for ComEd. The required amount of nuclear generation redispatch for these type of contingencies 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. Note that for NERC Type C simultaneous contingencies, generation redispatch is not considered to be an option to keep initial flows below cascading levels.^{**}

If the criteria described in this document cannot be met, mitigation plans are developed. A valid mitigation plan will bring the system into compliance through the most judicious use of a variety of feasible options. These include the development of an operator action plan in conjunction with the use of short-term ratings, generation redispatch, phase angle regulator adjustments, bus-tie switching, special protection systems, or the installation of a physical reinforcement.

^{*} For 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.

^{**} As a proxy for cascading ComEd uses the lower of the relay loadability rating or 115% of the load dump rating. PECO uses the lower of the relay loadability rating or 130% of the long-term emergency rating.

A Special Protection System (SPS), as interpreted from the NERC Reliability Standards Glossary of Terms, is designed to detect abnormal system conditions and take automatic corrective action to provide acceptable transmission system performance. The SPS isolates equipment other than faulted elements and/or reconfigures equipment outside of a zone containing faulted elements. An SPS may be applied as required to address thermal, voltage, or stability issues in accordance with NERC Transmission Planning (TPL) Standards and is subject to the SPS requirements of NERC Protection and Control (PRC) Standards 012-0 through 017-0. An SPS does not include automatic restoration to service of unfaulted elements within a faulted zone. SPSs also do not include under frequency and under voltage load shedding schemes, conventional generator out of step tripping schemes, or remote backup tripping schemes.

Operating steps implemented as part of a special protection system shall be considered, provided that the failure of such system does not result in cascading outages or overloads. For detailed discussion of operator action mitigation plans on the ComEd system, see appendix titled ComEd Operating Steps.

In addition to those events and circumstances included in Tables 1A and 1B, more severe but less probable scenarios should also be considered for analysis to evaluate resulting consequences. As permitted in the NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate. Such events are listed in category D of the NERC TPL Standards.

**Table 1A
ComEd Adequacy Criteria**

Outage Event	Facilities Operated at 345kV or Higher			Facilities Operated at 138kV and Under		
	50/50 Load Forecast	90/10 Load Forecast	Voltage (p.u.)	50/50 Load Forecast	90/10 Load Forecast	Voltage (p.u.) 138kV
None	All Facilities Within Normal Ratings	All Facilities Within Long-Term Emergency Ratings (4)	0.98 min (6) 1.03 max (5)	All Facilities Within Normal Limits	All Facilities Within Long-Term Emergency Limits (4)	0.95 min (6) 1.03 max (5)
1 Line or 1 Transformer or 1 open CB	All Facilities Within Short-Term Emergency Ratings (2)	All Facilities Within Short-Term Emergency Ratings (2)	0.95 min (6) 1.05 max	All Facilities Within Short-Term Emergency Ratings (2)	All Facilities Within Short-Term Emergency Ratings (2)	0.92 min (6) 1.05 max
1 Generator	All Facilities Within Short-Term Emergency Ratings (1)	All Facilities Within Short-Term Emergency Ratings (2)	0.95 min (6) 1.05 max	All Facilities Within Short-Term Emergency Ratings (1)	All Facilities Within Short-Term Emergency Ratings (2)	0.92 min (6) 1.05 max
2 Lines or 1 Line & 1 Transformer or 2 Transformers	All Facilities Within 100% Load Dump Ratings (3)	Not required	0.95 min (6) 1.05 max	All Facilities Within Cascading Levels (3) (7)	Not required	0.92 min (6) 1.05 max
1 Line & 1 Generator or 1 Transformer & 1 Generator	All Facilities Within Short-Term Emergency Ratings (2)	Not required	0.95 min (6) 1.05 max	All Facilities Within Short-Term Emergency Ratings (2)	Not required	0.92 min (6) 1.05 max
2 Underground Lines, Chicago business district only	All Facilities Within Short-Term Emergency Ratings (2)	All Facilities Within Short-Term Emergency Ratings (2)	0.95 min (6) 1.05 max	All Facilities Within Short-Term Emergency Ratings (2)	All Facilities Within Short-Term Emergency Ratings (2)	0.92 min (6) 1.05 max
2 Generators	All Facilities Within Short-Term Emergency Ratings (2)	Not required	0.95 min (6) 1.05 max	All Facilities Within Short-Term Emergency Ratings (2)	Not required	0.92 min (6) 1.05 max
1 Double Circuit Tower Line (simultaneous) or 1 Faulted Circuit Breaker or 1 Bus Section	All Facilities Within Cascading Levels (2) (7)	Not required	0.95 min (6) 1.05 max	All Facilities Within Cascading Levels (2) (7)	Not required	0.92 min (6) 1.05 max

- (1) Must return to normal ratings post contingency
- (2) Must return to long-term emergency ratings post contingency
- (3) Must return to long-term emergency ratings post contingency, adjustments other than load shed allowed pre-contingency of second non-simultaneous outage
- (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) 1.05 at generating stations
- (6) 0.98 at nuclear generating stations with one or more units on-line or with all units off-line
 0.98 at coal, combined cycle, combustion turbine generating stations with one or more units on-line
 0.98 at coal, combined cycle, combustion turbine generating station with all units off-line and plant auxiliaries supplied from unregulated* power sources
 0.95 at coal, combined cycle, combustion turbine generating station with all units off-line and plant auxiliaries supplied from regulated** power sources
- (7) As a proxy for cascading, ComEd uses the lower of the relay loadability rating or 115% of the load dump rating

*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
PECO Adequacy Criteria**

Outage Event	500kV Facilities		230kV Facilities		138kV Facilities		69kV Facilities	
	Thermal	Voltage (p.u.) (6), (7)	Thermal	Voltage (p.u.) (7)	Thermal	Voltage (p.u.) (6), (7)	Thermal	Voltage (p.u.) (6), (7)
None	All Facilities Within Normal Limits	1.0-1.02 min 1.076-1.1 max	All Facilities Within Normal Limits	0.98 min 1.05 max	All Facilities Within Normal Limits	0.98 min 1.014-1.05 max	All Facilities Within Normal Limits	0.957-0.98 min 1.022-1.05 max
1 Line 1 Transformer 1 Generator 1 Bus Section 1 Breaker Opening 1 Capacitor Bank	All Facilities Within Emergency Limits (1)	0.97-0.996 min 1.076-1.1 max	All Facilities Within Emergency Limits (1)	0.95 min 1.05 max	All Facilities Within Emergency Limits (1)	0.95 min 1.014-1.05 max	All Facilities Within Emergency Limits (1)	0.913-0.95 min 1.022-1.05 max
1 Line, Transformer, Generator, Bus Section, Breaker Opening or Capacitor Bank, followed by 1 Line, Transformer or Generator (4)	All Facilities Within Emergency Limits	0.97-0.996 min 1.076-1.1 max	All Facilities Within Emergency Limits	0.95 min 1.05 max	All Facilities Within Cascading Levels (2) (8)	0.928-0.95 min 1.014-1.05 max	All Facilities Within Emergency Limits (3)	0.913-0.95 min 1.022-1.05 max (3)
1 Double Circuit Tower Line (simultaneous) 1 Faulted Circuit Breaker	All Facilities Within Emergency Limits	0.97-0.996 min 1.076-1.1 max	All Facilities Within Emergency Limits	0.95 min 1.05 max	All Facilities Within Cascading Levels (2) (8)	0.928-0.95 min 1.014-1.05 max	See Note (5)	See Note (5)

- (1) must return to normal limits post contingency
- (2) must return to emergency limits post contingency
- (3) up to intermediate load level only
- (4) non load shed adjustment allowed prior to second event; consequential load loss up to 300 MW allowed after second event
- (5) not tested nor monitored, since 69 kV is not considered part of the bulk electric system
- (6) varies by location as follows:

	<u>Normal</u>	<u>Emergency</u>
For 500kV		
Elroy	1.0-1.1	0.97-1.1
Limerick	1.02-1.1	0.996-1.1
Peach Bottom	1.02-1.076	0.996-1.076
Whitpain	1.0-1.1	0.97-1.1
For 138kV		
Bradford	0.98-1.014	0.95-1.014
Newlinville	0.98-1.014	0.95-1.014
All Other 138kV	0.98-1.05	0.928-1.05
For 69kV		
Burholme	0.957-1.05	0.913-1.05
Cedarbrook	0.957-1.05	0.913-1.05
Chester	0.98-1.022	0.95-1.022
Eddystone	0.98-1.022	0.95-1.022
Moser	0.957-1.05	0.913-1.05
Paper Tap	0.98-1.022	0.95-1.022
Whitemarsh	0.957-1.05	0.913-1.05
All Other 69kV	0.98-1.05	0.95-1.05

- (7) Maximum Instantaneous Voltage Change as follows:
 - a. For 500 kV = 5%
 - b. For 230 kV = 7%
 - c. For 138 kV = 7%
 - d. For 69 kV = 7%
- (8) As a proxy for cascading, PECO uses the lower of the relay loadability rating or 130% of the long-term emergency rating

Minimum Normal and Emergency Voltage Limits at ComEd 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. Minimum transmission voltage limits specific to generating stations, are used to ensure plant auxiliary equipment is provided with adequate voltages during both on-line and off-line operation. These limits apply to all classes of generation except wind turbines, for which the system transmission voltage limits are adequate.

With the exception of nuclear generating stations, a minimum voltage limit of 0.98 per unit is established as a transmission voltage proxy for adequate plant auxiliary voltages supplied from power transformers not equipped with a load tap changer (or equivalent voltage control device) to control or regulate secondary voltage levels. The 0.98 per unit limit applies to both on-line and off-line generators with auxiliary equipment served from power transformers not equipped with a load tap changer. It is important to note that some portion of an on-line generator's auxiliary equipment is normally served from a plant auxiliary transformer not equipped with a load tap changer. A minimum voltage limit of 0.95 per unit is established for off-line generators with auxiliary equipment served from power transformers equipped with a load tap changer (or equivalent voltage control device) to control or regulate secondary voltage levels. The voltage compensation available from load tap changer operation is typically in the range of plus or minus 10%, which is expected to provide adequate plant auxiliary voltages for transmission voltage levels of 0.95 per unit and above.

For nuclear generating stations, a minimum voltage limit of 0.98 per unit is established as a transmission voltage proxy for adequate plant auxiliary voltages, which applies to both on-line and off-line generators.

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 basic references for system peak load to be used in studies for future years are the total corporate system load projection provided by the PJM Load Analysis Subcommittee and the substation load forecasts provided by the Capacity Planning Group. The actual peak load in any given future year is likely to be higher or lower than the forecast value. 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 5% higher than the '50/50' forecast.

3.2.1.2 Off-Peak Period Studies

Studies should also be conducted for the purpose of determining risks and consequences at light load or shoulder peak conditions, and for any other period for which system adequacy cannot be evaluated from peak period study results. For these off-peak periods, it is assumed that the number of hours of occurrence is substantially higher than the number of hours at or near peak load levels.

3.2.2 Multiple Contingencies / Common Mode Failures

Credible contingencies more severe than those included in Tables 1A and 1B shall also be considered for analysis. The types of contingencies considered for this analysis are defined in NERC TPL Standards as Category D. The transmission systems shall be evaluated for the risks and consequences of a number of each of these extreme contingencies, as listed below:

- Loss of a tower line with three or more circuits
- Loss of all transmission lines on a common right-of-way
- Loss of a substation
- Loss of a switching station
- Loss of a generating station
- Loss of a major load center
- Failure of a special protection system to operate when required
- Mis-operation of a special protection system
- Impact of severe power swings or oscillations from disturbances in another Regional Council
- Loss of the most critical transmission line followed by the loss of another critical transmission line in the same or adjacent system
- Single phase to ground fault with a failure of a protective device
- Loss of all lines at one voltage level at one substation
- A multi-phase fault with delayed clearing

3.2.3 Power Transfers

All studies should consider known firm power transfers affecting the Exelon transmission system. This includes known firm transmission service reservations, including those with rollover rights, as well as parallel path power transfers through the system that may impact system reliability.

ComEd and PECO are part of a larger regional power system that must be capable of withstanding certain levels of power transfers between or through sub areas of the region. PJM conducts load and generator deliverability tests for specific sub areas as part of the Regional Transmission Expansion Plan (RTEP) process to determine whether the system can accommodate these transfers. The ComEd and PECO systems must meet these transfer Load and Generator Deliverability Procedures. A description of the deliverability testing procedures can be found on the PJM web site. Reliability*First* also performs transfer limit testing to trend the strength of the transmission system. PJM's resource reliability criterion is a loss of load

expectation (LOLE) of .04 day per year for each zone in PJM and 0.1 day per year for PJM as a whole.

3.2.4 Equipment Ratings

Allowable loadings for transmission facilities are available in an equipment ratings database. In most cases, equipment is given at least a normal and one emergency rating. Some equipment is given multiple emergency ratings. These ratings differ by allowable duration, and are referred to as short-term, long-term, and load dump. In general, the duration associated with each rating is provided in the following tables.

ComEd

Description	Normal	Long-Term Emergency	Short-Term Emergency	Load Dump
Overhead Conductor	Continuous	> 30 minutes	30 minutes	15 minutes
Terminal Equipment	Continuous	> 30 minutes	30 minutes	15 minutes
Transformers (Autos)	Continuous	> 4 hours	30 minutes	15 minutes
Phase Angle Regulators	Continuous	> 4 hours	2 hours	15 minutes
Underground Cable	Continuous	> 3 hours	2 hours	15 minutes

PECO

Description	Normal	Long-Term Emergency	Load Dump
Overhead Conductor	Continuous	< 4 hours	15 minutes
Terminal Equipment	Continuous	< 4 hours	15 minutes
Transformers (Autos)	Continuous	< 4 hours	15 minutes
Underground Cable	Continuous	< 4 hours	15 minutes

The specific procedure used for determining equipment ratings is outlined in the Exelon Transmission Ratings Methodology technical reference document. Loadability for overhead and underground lines and for transformers is based in part upon the thermal limitations of equipment components. These limitations are set to obtain a reasonable useful life (40 to 50 years) of the equipment throughout normal and emergency use. Insulated equipment such as cables or transformers is subject to aging of the insulation. The rate of aging is dependent on conductor temperature attained and the duration of the loading. Overhead conductors may be limited by insulation life. For bare conductors, the principle concern is sag restrictions, but ratings may be further limited by the loss of mechanical strength of the conductor. In addition, the rating of a given line may be limited by thermal limitations of connected equipment, such as switches, circuit breakers, buses, and metering or protective relaying equipment.

Emergency capabilities apply only to the infrequent higher loading of equipment necessitated by the unintentional loss of other equipment, or for unexpectedly high system loads. During planned outages, all transmission elements shall be within their normal ratings for a pre-contingency scenario.

Equipment ratings are issued to all appropriate areas of the company and are used by both planning and operating personnel, although ambient adjusted ratings are available to the transmission dispatchers on some PECO facilities.

3.2.5 Circuit Breaker Interrupting Capability

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

3.2.6 Reactive Power Planning

The objective of system reactive power planning is to efficiently coordinate the reactive requirements of the transmission and distribution systems to satisfy voltage criteria. Meeting this objective ensures voltage stability, provides generator auxiliary power systems on the distribution system with adequate voltage, and minimizes transmission losses and reactive interchange. System reactive requirements can be supplied by generating units, transmission, sub-transmission, and distribution level static capacitors, synchronous condensers and by a variety of solid-state reactive compensation devices (SVCs, STATCONS, etc.).

The Exelon system is planned so that transmission voltages will be maintained within an acceptable range for normal and emergency conditions as described in Table 1A and 1B. Low transmission voltage will lead to undesirable effects in both the transmission and distribution systems, such as higher losses, reduced insulation life, and reduced effectiveness of capacitors. These effects would also increase the difficulty in recovering from low transmission voltage situations. The outage events analyzed to assess voltage adequacy are the same as those listed in Tables 1A and 1B.

Transmission voltage levels must be coordinated to provide adequate distribution system voltages under transmission system normal and emergency conditions. Factors affecting transmission voltage include:

- Generator voltage
- Loading of substation transformers and transmission lines
- Transformer no-load tap setting
- LTC range of the transformer
- Transformer impedance
- Compensated load power-factor as seen from the substation bus
- Switchable shunt capacitors at the substation
- Equipment out of service

Analysis should be performed to determine the compensated load power factor and transformer no-load tap setting combinations that will best satisfy the transmission voltage requirements, distribution substation loading criteria, and substation voltage criteria.

Specific criteria for system voltage stability are given in Section 4.2.

4. Exelon Transmission Planning Security Criteria

It is not possible to design a system that can provide continuous supply to all load for all possible combinations of equipment outages. Planning criteria must represent a balance between cost and reliability. For some severe unlikely outage combinations, it may be necessary to drop some load or generation. However, the system should be designed to avoid cascading outages, instability, or widespread blackout.

Ensuring system security implies protecting the system against uncontrolled loss of load over large areas. Double contingency events should not result in uncontrolled loss of load, but can result in a planned/controlled loss of load. Generator angular instability can occur for some locations following close-in bolted three phase faults followed by a protection system failure (relay, circuit breaker, or stabilizer). More often, however, even lower probability extreme events such as the outage of an entire substation, generating station, or right-of-way or even more extreme combinations would be required to cause cascading thermal overloads or voltage collapse. Appropriate solutions to such low probability but severe events could involve the undesirable but necessary tripping of generation or automatic or manual shedding of load in order to regain control of a dynamically unstable condition.

4.1 Generator Rotor Angular Stability

4.1.1 General

Generator rotor angular stability refers to maintaining the generator rotor electrical orientation in synchronization with that of the transmission system. The bulk power system is designed to maintain generator stability following reasonably severe transmission system disturbances. If the system remains stable for these disturbances, it should also be stable for a broad range of less severe, though more likely events.

4.1.2 System Representation

In simulating transmission system disturbances, conservative assumptions are made for related factors. For example, the generators at the plant under study are assumed to be operated at full power output, and the three-phase zero-impedance fault can be placed at the plant high voltage bus where it has the greatest impact on the generators. Reactive power output of the plant can be assumed to be the minimum possible at the real power output level being studied. Other effects, such as power interchange with other companies and system load level, are considered on a case-by-case basis to the extent that they affect system stability.

4.1.3 Studied Contingencies

Studies are performed to determine if generator angular stability will be maintained at any possible output level for faults applied to transmission or generation elements of the system. These elements include lines, transformers, circuit breakers, shunt capacitors, shunt inductors,

buses, series capacitors, series inductors, generators, synchronous condensers, static var compensators (SVC), static condensers (STATCON), or other power carrying devices. The following events are studied:

ComEd

- 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 any transmission or generation element with delayed clearing due to failure of a special protection system.
- 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.

It should be noted that a one-cycle margin is included in all primary-clearing times to account for simulation uncertainty. For relatively low probability events such as faults occurring simultaneously during maintenance outages and faults cleared in delayed time, it is recommended but not required that the system remain stable with an explicit one cycle margin. If the system is found to be unstable under these less probable circumstances, then low cost solutions will be pursued.

PECO

- A three-phase fault with normal clearing time.
- A single phase to ground fault with a stuck breaker or other cause for delayed clearing.
- The loss of any single facility with no fault.

In addition to these contingencies, other more severe events may be studied to measure the robustness of the transmission system. They are as follows:

- Sudden loss of the entire generating capability of any station for any reason.
- The sudden loss of all lines of one voltage emanating from a substation.
- The sudden loss of all lines in a common right-of-way.
- The sudden dropping of a large load or a major load center.
- The occurrence of a multi-phase fault with delayed clearing.

4.1.4 Fault Clearing Times

Fault clearing time can vary due to the protective equipment used, the transmission system configuration, or transmission voltage level. If simulated faults are intended to model those cleared following the failure of a protective relay or circuit breaker, the clearing time is determined by combining the operation times of the backup relay and breaker for the particular

site being studied. This combined operation time is defined as the total clearing time. Typical clearing times used for stability studies are shown in the following table:

Voltage	ComEd		PECO	
	Normal	Delayed	Normal	Delayed
765kV	5-6 cycles	8-14 cycles	--	--
500kV	--	--	3.5 cycles	8 cycles @ nuclear stations 12 cycles @ all other locations
345kV	5-6 cycles	8-14 cycles	--	--
230kV	--	--	4.5 cycles	12 cycles @ nuclear stations 15 cycles @ all other locations
138kV	5-6 cycles	12-16 cycles	7.5 cycles	20 cycles
69kV	--	--	10.5 cycles	23 cycles

4.1.5 Determination of Stability

Both the maximum angular swing of the generator rotor and the damping of the rotor oscillations following a disturbance define generator rotor angular stability. If a generator rotor angle exceeds 180 electrical degrees with respect to the transmission system, it is deemed to have slipped a pole and is certainly unstable. If a maximum generator rotor electrical angle with respect to the system is large, further analysis may be required to determine if the generator is defined as being marginally stable because of the significant electrical disturbance experienced by the transmission system. In these cases, an acceptably stable situation 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.

4.1.6 Machine Stability Mitigation

Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies. Not all severe events can be protected against. However, the system should be secure from cascading outages for any single contingency, double contingency, single contingency with delayed clearing, and for selected extreme disturbances. Testing for security from these events must incorporate evaluation of protection system settings, and short time (minutes) emergency loading capabilities of equipment. Load shedding may be necessary to keep equipment from exceeding long-term (hours) emergency ratings, and sufficient time must exist to accomplish necessary shedding. Load shed requirements associated with known contingency conditions within criteria must be documented.

Mitigation options for more extreme events causing generator angular instability may include the installation of special protection systems.

4.2 Transmission Voltage Stability

4.2.1 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. Transmission system voltage instability can occur with combinations of unusual and severe equipment outages (possibly in other control areas), high power transfers, and/or high system load. The system should be planned to avoid transmission voltage instability for the various outage conditions considered for the bulk power transmission system.

Adequate voltage stability margins are achieved by allocating sufficient reactive reinforcements while adhering to criteria for steady state minimum and maximum voltages. Adequate dynamic reactive reserves must be available to prevent post-contingency voltage instability. System reinforcements designed to improve voltage stability margin generally increase reactive reserves. However, reactive reserves provide an indirect, and therefore, limited measure of voltage stability. The measure is indirect because the location of reactive reserves influences the relative impact on voltage stability.

4.2.2 System Representation

Generation dispatch and reactive capability should be modeled consistent with Regional Transmission Organization (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. Historical loads should be considered but may require adjustment if regional or local changes are anticipated. The expected transmission system configuration, including reinforcements and other material changes, should represent the time period under study.

4.2.3 Studied Contingencies

4.2.3.1 Long-Term Analysis

The system will be planned to avoid transmission voltage instability for the various outage conditions summarized in Table 2.

Normal system conditions (i.e. with no contingencies) and single contingencies are evaluated utilizing a '90/10' forecast load plus appropriate simulation margin. Multiple contingencies are evaluated utilizing a '90/10' or '50/50' forecast load.

4.2.3.2 Near-Term Analysis

When conducting simulations to determine near-term system voltage stability, such as a current day voltage stability analysis, the expected system configuration should be modeled. All

subsequent single contingency transmission element or generating unit outages should be evaluated versus the expected peak load level for the appropriate time period plus an appropriate margin. The margin accounts for modeling uncertainties and provides advanced warning so that operators may take appropriate actions.

4.2.4 Determination of Stability

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. The maximum power transfer point is the total system load corresponding to the point of instability of the weakest transmission system bus. Voltage stability criteria are satisfied when simulation results demonstrate that voltage stability margin is greater than zero and sufficient voltage levels are maintained to avoid localized load cycling 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. Operation of the transmission system within applicable limits ensures that adequate distribution system and generator auxiliary bus voltages can be maintained.

Dynamic reactive capability should be sufficient to ensure that the transmission system can appropriately transition between steady-state operating conditions following a disturbance, i.e. remain stable.

4.2.5 Voltage Stability Mitigation

Mitigation options for more extreme events causing voltage instability include consideration of automatically switched reactive compensation devices, dynamic reactive resources, and under-voltage load shedding.

Table I of the NERC TPL Standards is considered in determining the threshold load level and whether application of an under voltage load shedding (UVLS) or manual load shedding scheme is an acceptable mitigation option. Table 2 summarizes voltage stability criteria including a description of the contingency, the NERC TPL Standard event category, the type of fault, the applicable threshold load level, and the mitigation options.

The planned operation of UVLS protection is limited to the contingencies for which UVLS is an acceptable mitigation option per Table 2.

Table 2 – Transmission Facility Voltage Stability Criteria

Outage Event	NERC TPL	Threshold Load Level		Mitigation Options	
	Category*	ComEd	PECO	ComEd	PECO
None	A	90/10 forecast +750 MW	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of a Generator due to 3 Phase or SLG Fault	B	90/10 forecast +500 MW	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of a Transmission Element due to 3 Phase or SLG Fault**	B	90/10 forecast +500 MW	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of a Generator followed by Loss of another Generator due to 3 Phase or SLG Faults	C	90/10 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement
Loss of a Generator followed by Loss of a Transmission Element due to 3 Phase or SLG Faults	C	90/10 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement
Loss of a Generator followed by Loss of another Generator due to 3 Phase or SLG Faults	C	50/50 forecast	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of a Generator followed by Loss of a Transmission Element due to 3 Phase or SLG Faults	C	50/50 forecast	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of Double Circuit Tower Line due to SLG Faults	C	50/50 forecast	50/50 forecast	Requires Reinforcement	Requires Reinforcement
Loss of a Transmission Element followed by Loss of a Transmission Element due to 3 Phase or SLG Faults	C	50/50 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement
SLG on a Bus Section	C	50/50 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement
SLG Fault on a Transmission Element w/Delayed Clearing	C	50/50 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement
SLG Fault on a Circuit Breaker	C	50/50 forecast	50/50 forecast	UVLS is acceptable	Requires Reinforcement

* NERC TPL Standards Category D contingencies are only studied to evaluate their impact on the system. No mitigation is required.

** Lines, transformers, and synchronous condensers are considered transmission elements.

4.3 ComEd Dynamic Voltage Recovery

4.3.1 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. Motor loads respond to the resulting voltage transient by drawing additional reactive power. Reactive power supplied by capacitance on the system is proportional to the square of the terminal voltage, and therefore is simultaneously reduced. If the resulting surge in reactive power demand cannot be met, machines may stall, potentially leading to more severe voltage problems.

4.3.2 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.

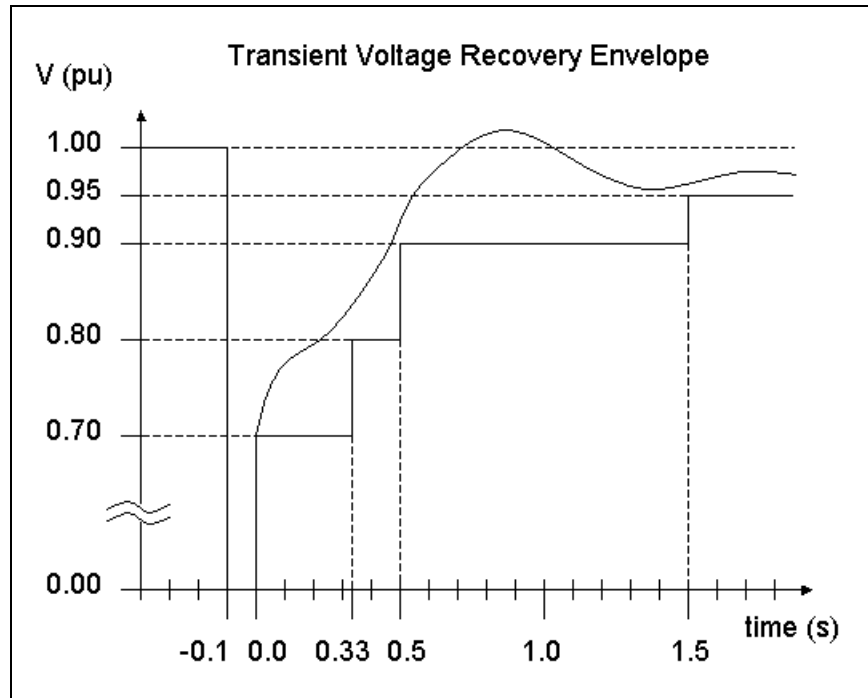
In addition to dynamic resources, transient voltages will also be influenced by factors that impact steady-state voltages. In particular, it is important to accurately model the correct status of any capacitors expected to be in service to support voltage stability and voltage adequacy.

4.3.3 Criteria

The DVR criteria should be satisfied at buses 138kV and above peak load, given all transmission elements are in 'normal' configuration preceding the event.

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.



4.3.4 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.

5. References

NERC Planning Standards – latest revisions available on the NERC website:

- Standard TPL-001-0 – System Performance Under Normal Conditions
- Standard TPL-002-0 – System Performance Following Loss of a Single BES Element
- Standard TPL-003-0 – System Performance Following Loss of Two or More BES Elements
- Standard TPL-004-0 – System Performance Following Extreme BES Events

Load and Generator Deliverability Procedures – latest revision available on the PJM website:

- Manual 14B: PJM Regional Planning Process – Attachment E: PJM Deliverability Testing Methods

APPENDIX

COMED OPERATING STEPS

Short time emergency ratings apply to contingencies shown in Table 1A if operating steps are identified that will eliminate the emergency overloads within a time period of 30 minutes for overhead facilities and 2 hours for underground facilities. The implementation of remedial switching operations carried out under the direction of system load dispatchers should be investigated in the determination of a mitigation plan. Equipment thermal time constants usually allow for 30 minutes (overhead) or 2 hour (underground) to perform limited switching operations following an equipment outage, before overloaded equipment reaches critical temperatures. Specific criteria have been established that must be satisfied before a switching operation can be recommended. The condition warranting operator action must be readily observable by or alarmed to the responsible dispatcher. Additionally, the switching operation must satisfy the following requirements:

- results in reduced risk of possible customer interruptions
- can be completed within a reasonable time frame, prior to equipment damage, using standard safety precautions and work practices
- has a reasonable implementation frequency
- does not involve extended interruption of load
- does not result in additional system stress
- has a net positive economic impact
- does not unduly burden neighboring systems
- does not significantly increase risk of generator or voltage instability

Examples of operating steps that should be evaluated at the planning stage include phase angle regulator adjustments, the operation of peaking units, bus-tie operations, or changes in generator supply through dispatch or switching at generating stations. Such operating steps that become part of the planned operation of the future system in order to avoid costly system reinforcements must be understood and formally agreed to by System Protection and operating personnel (Transmission Operations, the dispatch agent, and Distribution Dispatch) at the planning stage. Operating steps implemented through the operation of special relay protection schemes will be considered, provided that the failure of the scheme does not result in cascading outages or cascading overloads.

For planning purposes, a mitigation plan is required for transformers that exceed the long-term emergency rating for the contingencies specified in Table 1A. As with other mitigation plans, the transformer can exceed its long-term emergency rating with a 30 minute operating guide in effect. For planning purposes, the transformer can exceed its short term rating only if a special protection scheme is installed to reduce post contingency loading to within long-term emergency ratings automatically. The special protection scheme must coordinate with back-up protection. Failure of the scheme cannot result in cascading outages or cascading overloads.