Dominion Energy Virginia
Electric Transmission Planning Criteria

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A. Scope and objective

The function of the transmission system is to transport power from generating resources to distribution systems to serve the demand of the end-user customers. Reliable transmission system operation implies maintaining continuity of service at sufficient voltage levels without overloading equipment under a wide range of operating conditions.

Virginia Electric and Power Company is commonly referred to as Dominion Energy Virginia (DEV). In this document, “DEV transmission system” refers to the transmission system owned by DEV. “Transmission system” refers to networked and radial facilities within the DEV system at voltage levels of 69, 115, 138, 230, and 500 kV. This document provides approved criteria upon which the needs for reinforcements and enhancements to the DEV transmission system are determined.

DEV’s transmission planning criteria ensures adherence to the transmission planning standards of the North American Electric Reliability Corporation (NERC) and those of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations (RRO) of NERC. Unless noted, the Criteria in this document apply to generation, transmission, and end user facilities.

B. National and regional criteria and guides

B.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, the bordering provinces of Canada, and a portion of Mexico. 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 DEV Transmission Planning Criteria provides a description of how DEV performs simulated testing of the interconnected transmission system to determine its ability to withstand probable and extreme contingencies.

B.2. Regional reliability planning standards

NERC consists of eight regional reliability organizations. DEV is a member of the SERC Reliability Corporation (SERC), one of the eight regional reliability organizations of NERC. DEV plans the bulk electric system (BES) in coordination with PJM, its Transmission Planner (TP), to meet the requirements of NERC and SERC.

B.3. PJM planning standards

The DEV transmission system is integrated into planning and operations of the PJM Interconnections, L.L.C. RTO (PJM). 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 Region Transmission Planning Process.

C. Transmission planning, steady-state criteria

C.1. Planning principles and standards

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.

Tables 1A and 1B specify outage events that are analyzed by DEV at the forecasted load levels to determine if any thermal or voltage violations exist. 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 DEV’s transmission system meets the applicable reliability requirements of NERC, SERC, and PJM.

System readjustment is allowed when attempting to reduce line loadings or improve voltage profile (only as allowed by NERC Criteria). System readjustments considered in planning analysis include:

- Generation re-dispatch (excludes nuclear generation)
- Phase angle regulator adjustment[1]
- Load tap changer adjustment
- Capacitor bank switching
- Line switching
- Inductor switching
- Adjustment of Flexible AC Transmission System (FACTS) devices

Loadings on DEV transmission facilities over their normal rating, following a contingency, must be adjusted back down to normal rating within the time frame of the short-term emergency

[1] *For DEV, phase angle regulator adjustment is used to relieve loadings on the 115kV system in Yorktown and Chesapeake Energy areas. Phase shifting transformers control the division of real power among parallel paths. Chesapeake Energy Center and Yorktown Power Station have phase shifters between the 230 kV and 115 kV systems. The phase shifter transfers load from one voltage level to the other. Phase angle adjustment will be allowed within the parameters noted in PJM’s Manual 14B – PJM Region Transmission Planning Process (RTEP Reliability Planning section).*

rating. Any of the above listed system readjustments are allowable in this situation as DEV employs 8 hours short-term emergency ratings on transmission equipment, which allows sufficient time to implement any adjustments that reduce loadings to the normal rating.

Loadings on facilities over their short-term emergency ratings, following a contingency, must be adjusted back down to the short-term emergency rating within the 15-minute time frame of the load dump rating using the system readjustments listed above, which are only those readjustments that are feasible within 15-minutes by System Operators.

Dominion performs N-1-1 contingency analysis on transmission lines by taking a branch of a given line out of service as the first contingency. This mirrors real world conditions where after a fault takes an entire line out of service (breaker-to-breaker), branches of the line are restored through switching except for the branch that experienced the original fault. For the second contingency, breaker-to-breaker line outages are applied and analyzed.

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 re-dispatch, phase angle regulator adjustments, bus-tie switching, Remedial Action Schemes, or the installation of a physical reinforcement.

A Remedial Action Scheme (RAS), 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 RAS isolates equipment other than faulted elements and/or reconfigures equipment outside of a zone containing faulted elements. A RAS 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 RAS requirements of NERC Protection and Control (PRC) Standards 012 through 017. A RAS does not include automatic restoration to service of un-faulted elements within a faulted zone, under frequency and under voltage load shedding schemes, conventional generator out of step tripping schemes, or remote backup tripping schemes. DEV reviews all existing RASs periodically and adjusts settings as deemed necessary. DEV primarily installs RASs as a temporary measure until a more robust solution can be completed to provide acceptable system performance. Operating steps implemented as part of a Remedial Action Scheme shall be considered, provided that the failure of such system does not result in cascading outages or overloads.

In addition to those events and circumstances included in Tables 1A and 1B, Table 1C defines more severe but less probable scenarios that 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.

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type [2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	95%	105% & 103%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105% & 103%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	93%	105% & 103%
		2. Bus Section Fault	SLG	Yes	Yes	100% STE	90%	105% & 103%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	Yes	Yes	100% STE	90%	105% & 103%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	100% STE	90%	105% & 103%
P3 Multiple Contingency [see Dom Energy Note "A", "B" & C]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	93%	105% & 103%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note "B"]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Yes	100% STE	90%	105% & 103%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note "B"]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection Sytem[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Yes	Yes	100% STE	90%	105% & 103%

Table 1A continued on next page

Table 1A Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

HIGH VOLTAGE (HV): 230 kV, 138 kV, 115 kV & 69kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "B" & C]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	100% STE	90%	105% & 103%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	100% STE	90%	105% & 103%

Dominion Energy Notes for Table 1A

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

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Note "A" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "B" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.
Note "C" – System adjustment should be performed after first contingency event (Initial Condition).

* If the aggregated consequential or non-consequential load loss exceeds 300 MW, system reinforcements will be required.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3). A lower overvoltage limit of 103% is applied to 138KV facilities based on the age and number of legacy switches on the network at this voltage.

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	No	No	94% N	102.5%	108%
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	109.6%
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	No[9]	No[12]	94% STE	101%	109.6%
		2. Bus Section Fault	SLG	No[9]	No	100% STE	100%	109.6%
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	No[9]	No	100% STE	100%	109.6%
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	Yes	Yes	100% STE	100%	109.6%
P3 Multiple Contingency [see Dominion Energy Note "D", "E" & "F"]	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	No[9]	No[12]	94% STE	101%	109.6%
P4 Multiple Contingency *(Fault plus stuck breaker[10])* [see Dominion Energy Note "D"]	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	No[9]	No	100% STE	100%	109.6%
P5 Multiple Contingency *(Fault plus relay failure to operate)* [see Dominion Energy Note "D"]	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	No[9]	No	100% STE	100%	109.6%

Table 1B continued on next page

Table 1B Steady-State Performance PLANNING Events and Dominion Energy CRITERIA *(continued)*

EXTRA HIGH VOLTAGE (EHV): 500kV Facilities

NERC TPL-001 Events (excludes DC)						Dominion Energy Criteria		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Interruption of Firm Transmission Service Allowed[4]**	**Non-Consequential Load Loss Allowed***	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)* [see Dominion Energy Note "D" & "F"]	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	Yes	Yes	100% STE	100%	109.6%
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Yes	Yes	100% STE	100%	109.6%

<u>Dominion Energy Notes for Table 1B</u>

See separate listing *Table 1 (A & B) Footnotes* for superscript numbered footnotes.

Note "D" - See *Section C.2.1.3 – Critical stress case development and studies* for details.

Note "E" - Areas of the system that become radial post-contingency will be included for monitoring of thermal and voltage violations for all load levels served by the radial.

Note "F" – System adjustments should be performed after first contingency event (Initial Condition).

* If the aggregated consequential or non-consequential load loss exceeds 300 MW, system reinforcements will be required.

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).

N – Normal Rating

STE – Short Term Emergency

LD – Load Dump

Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA

NERC TPL-001 Events (excludes DC)					Dominion Energy Criteria		
Category	**Event Note "G"**		**Interruption of Firm Transmission Service Allowed**	**Non-Consequential Load Loss Allowed**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
N-2 Two Contingencies	Loss of a single generator, Transmission Circuit, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, shunt device, or transformer forced out of service <u>prior to System adjustments.</u>		YES	YES	100% LD	90%	Note "M"
LAE Local Area Events	Local area events affecting the Transmission System such as:	a. Loss of a tower line with three or more circuits.[11]	YES	YES	100% LD Note "H"	90%	Note "M"
		b. Loss of all Transmission lines on a common Right-of-Way[11].	YES	YES	100% LD Note "I"	90%	Note "M"
		c. Loss of a switching station or substation (loss of one voltage level plus transformers).	YES	YES	100% LD Note "J"	90%	Note "M"
		d. Loss of all generating units at a generating station.	YES	YES	100% LD Note "K"	90%	Note "M"
		e. Loss of a large Load or major Load center.	YES	YES	100% LD Note "L"	90%	Note "M"
WAE Wide Area Events	Wide area events affecting the Transmission System based on System topology such as:	a. Loss of two generating stations resulting from conditions such as: i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	YES	YES	100% LD for both HV and EHV		Note "M"
		b. Other events based upon operating experience that may result in wide area disturbances.	YES	YES			Note "M"

** Percent of Nominal Voltage (Note: Voltage limits for North Anna and Surry Power Stations are governed by the requirements of their respective Nuclear Plant Interface Requirements (NPIR) with Dominion Energy Electric Transmission as noted in Section E.3).
N – Normal Rating, STE – Short Term Emergency, LD – Load Dump

Dominion Energy Notes for Table 1C

See separate listing *Table 1 (A, B & C) Footnotes* for superscript numbered footnotes.

Note “G” – For all extreme events evaluated:

- Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Note “H” – The loss of three or more transmission circuits on a common structure should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common structure and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “I” – The loss of transmission circuits on a common right of way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right of way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.

Note “J” – The loss of a switching station or substation (one voltage level plus transformers) should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE). The consequential load due to the loss in the affected station is not to exceed 300 MW.

Note “K” – The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “L” – The loss of a large load or major load center should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than its load dump rating during the period required to make prompt power supply adjustments to reduce overloads to less than its emergency rating (STE).

Note “M” - High Voltage (HV): 105%; Extra High Voltage (EHV): 109.6%

Table 1 (A, B & C) Footnotes [NERC Standard TPL-001-4]

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage apply to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant component of a Protection System to consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communication system that is both monitored and reported at a Control Center;
    c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

C.1.1. Voltage limits at generating stations

Plant auxiliary power equipment requires adequate voltages in order to maintain reliable operation of online generators as well as to provide for reliable startup capability for offline generators. Minimum transmission voltage limits specific to generating stations, are used to ensure plant auxiliary equipment is provided with adequate voltages during both online and offline operation. These limits apply to all classes of generation except wind turbines, for which the system transmission voltage limits are adequate.

In cases where plant auxiliary power is supplied by power transformers not equipped with a load tap changer (LTC) or equivalent voltage control device, the voltage limits at the low side of the Generator Step-up Unit (GSU) are established as 0.95 per unit (minimum) and 1.05 per unit (maximum) unless otherwise specified by the generator owner.

C.2. Detailed steady-state criteria

C.2.1. System load level

C.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. The actual peak load in any given future year is likely to be higher or lower than the forecast value. A ‘50/50’ forecast provides a peak load projection with a 50% probability that the actual peak will be higher than the level forecasted in that year.

C.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. In addition, severe drought conditions effecting hydro generation plant availability and its impact on the transmission system are also studied.

C.2.1.3. Critical stress case development and studies

DEV studies the transmission system under both normal and critical system stress conditions. For NERC Category P3 Analysis, DEV will outage the most critical generator in the area being studied, and the resulting power flow case is considered a critical stress case. Under this critical stress case condition, the generator being studied is taken off-line and the remaining generators connected to the DEV System are proportionally increased to make-up for the lost generation. If there are not enough generation resources available within the DEV system, or the use of DEV generation resources would not provide an adequate base case, then PJM generation resources should be utilized to make-up any generation deficiency. This resulting critical stress case is then analyzed for NERC Compliance based on the transmission contingency events listed in Table 1A and Table 1B Category P3(Multiple Contingency).

C.2.2. Power transfers

All studies should consider known firm power transfers affecting the DEV 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.

DEV is 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 DEV transmission system must meet this transfer Load and Generator Deliverability Requirement. A description of the deliverability testing procedures can be found in PJM Manual 14B – PJM Region Transmission Planning Process[2]. SERC Reliability Corporation also performs transfer limit testing to trend the strength of the transmission system. The results of these studies may also indicate a need to increase transfer strength on the DEV system.

DEV routinely tests the capability of the transmission system to transfer reasonable amounts of power (approximately 2000 MW) in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities. Such tests are conducted under two basic scenarios: (1) with all transmission facilities in service at or below the maximum continuous normal rating; and (2) with one transmission circuit or transformer out of service while maintaining the loading on all remaining transmission facilities at or below the maximum continuous emergency rating. Any new facilities connected to the transmission system shall not significantly decrement, the First Contingency Incremental Transfer Capability (FCITC) for transfers between utilities. A FCITC decrement in excess of 5% will be considered significant in most cases.

[2] Based on DEV criteria for Generation Deliverability, the thermal thresholds for Single contingencies (NERC P1 category) and Non-Single contingencies (NERC P2, P4, and P7 categories) are 94% of Short Term Emergency (STE) and 100% of Load Dump (LD), respectively.

C.2.3. Equipment ratings

Allowable loadings for transmission facilities are maintained by DEV in an equipment ratings database. In most cases, equipment is given at least a normal rating 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.

The specific procedure used for determining equipment ratings is outlined in the DEV Transmission Facility Ratings Methodology technical reference document.

C.2.4. Circuit breaker interrupting capability

All Facilities must equal or exceed the fault duty capability necessary to meet system short circuit requirements as determined through short circuit analyses, and shall fully comply with the latest ANSI/IEEE C37 standards for circuit breakers, switch gear, substations, and fuses.

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 phase fault or three phase-to-ground fault.

C.2.5. 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 controlled by changing generation excitation, operating synchronous condensers, changing transformer tap positions, switching transmission and distribution level static capacitors, switching shunt reactors, and adjusting solid-state reactive compensation devices (SVCs, etc.).

The DEV system is planned so that transmission voltages will be maintained within an acceptable range for normal and emergency conditions as described in Tables 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. Distribution facilities which are maintaining power factors at the Transmission Point of Interconnection (POI) that are less than PJM's requirement (per Manual 14B – PJM Region Transmission Planning Process) and DEV's requirement (97.3% lagging) may not be able to maintain satisfactory voltage to customers served from these distribution facilities when transmission system voltages are at or near the lower voltage limits of normal and emergency transmission system operations.

Conversely, high transmission voltages that exceed operating voltage schedules can stress generation, distribution, and transmission equipment and lead to premature fatigue or even failure.

C.2.6. Radial transmission lines

A Radial transmission line is defined as a single line that has one transmission source, serves load, and does NOT tie to any other transmission source (line or substation). Unlike load served from a network transmission line having two sources where a downed conductor or structure can be sectionalized for load to be served before repairs are completed, load served from a single source radial transmission line cannot be reenergized until all repairs to the line are completed. Accordingly, loading on single source radial transmission lines will generally be limited to the following:

- 100 MW Maximum
- 700 MW-Mile Exposure (MW-Mile = Peak MW X Radial Line Length)

A factor in evaluating the load limitation on a radial transmission line is the degree to which the distribution load can be switched to circuits served from other sources and whether such capability can be reasonably added. Other factors include the ability to perform maintenance on the radial transmission line, the outage history of the radial transmission line, load density and type, tie capability, etc.

Once a radial loading limit exceeds any of these thresholds, an additional transmission source may be required. Acceptable transmission sources include but are not limited to the following:

- Network from a separate transmission substation source (Preferred)
- Loop back to same transmission substation source
- Normally open network or loop transmission source

C.2.7. Network transmission lines – Limitations on direct-connect loads

A network transmission line is defined as one that connects two network transmission sources (connect to other lines & substations) and a “Tap point” is defined as a direct connection of a customer to a network transmission line without addition of any transmission breaker or breakers to split the line. Network transmission lines facilitate network flows and could serve directly connected (Tapped) loads. In the Dominion Energy system, 500, 230, 138, 115 and 69kV lines are considered transmission, and all with the exception of 500kV could be tapped to serve customer load.

In general, the number of direct-connect loads (tapped facilities) should be limited to four (4); however, Good Utility Practice and sound engineering judgment must be exercised in application of this criteria.

C.2.8. Substation – Limitation on direct-connect loads

The amount of direct-connect load at any substation will be limited to 300MW.

C.2.9. End of life criteria

Electric transmission infrastructure reaches its end of life as a result of many factors. Some factors such as extreme weather and environmental conditions can *shorten* infrastructure life, while others such as maintenance activities can *lengthen* its life. Once end of life is recognized, in order to ensure continued reliability of the transmission grid, a decision must be made regarding the best way to address this end-of-life asset.

For this criterion, “end of life” is defined as the point at which infrastructure is at risk of failure, and continued maintenance and/or refurbishment of the infrastructure is no longer a valid option to extend the life of the facilities consistent with Good Utility Practice and Dominion Energy Transmission Planning Criteria. The infrastructure to be evaluated under this end-of-life criteria are all regional transmission lines operated at 500 kV and above.

The decision point of this criterion is based on satisfying two metrics:

1) *Facility is nearing, or has already passed, its end of life, and*
2) *Continued operation risks negatively impacting reliability of the transmission system.*

For facilities that satisfy both of these metrics, this criterion mandates either replacing these facilities with in-kind infrastructure that meets current Dominion Energy standards or employing an alternative solution to ensure the Dominion Energy transmission system satisfies all applicable reliability criteria.

Dominion Energy will determine whether the two metrics are satisfied based on the following assessment:

1. End of Life

Factors that support a determination that a facility has reached its end of life include, but are not limited to,

- **Condition** of the facility, taking into consideration:
  - Industry recommendations on service life for the particular type of facility
  - The facility's performance history
    - Documented evidence indicating that the facility has reached the end of its useful service life
  - The facility's maintenance and expense history
- **Third-party assessment -** While not required, Dominion Energy has the option of seeking a third-party assessment of a facility to determine if industry specialists agree the facility has reached the end of its useful service life

2. Reliability and System Impact

The reliability impact of continued operation of a facility will be determined based on a planning assessment and operational performance considerations. The end-of-life determination for a facility to be tested for reliability impact will be assessed by evaluating the impact on short term and long term reliability with and without the facility in service. The existing system with the facility removed will become the base case system for which all reliability tests will be performed.

The primary four (4) reliability tests to be considered are:

1. NERC Reliability Standards
2. PJM Planning Criteria – As documented in PJM Manual 14B – PJM Region Transmission Planning Process
3. Dominion Energy Transmission Planning Criteria contained in this document
4. Operational Performance – This test will be based on input from PJM and/or Dominion Energy System Operations as to the impact on reliably operating the system without the facility

Additional factors to be evaluated under system impact may include but not be limited to:

1. Market efficiency
2. Stage 1A ARR sufficiency
3. Public policy

4. SERC reliability criteria

Failure of any of these reliability tests, along with the end-of-life assessment discussed herein, will indicate a violation of the End-of-Life Criteria and necessitate replacement as mandated earlier in this document.

After the end of service life and reliability impact of a facility are evaluated and it has been determined that the facility violates the End-of-Life Criteria, a determination will be made as to whether replacement of the facility is the most effective solution for an identified reliability need, or whether an alternative solution should be employed. One or more of the following factors may be considered in determining whether to proceed with facility replacement or with an alternative solution:

- Planning analysis which may include power flow studies
- Operational performance
- System Reliability
- Effectiveness of the alternative as compared to the replacement facility
- Future load growth in the study area
- Future transmission projects or interconnects that impact the study area
- Constructability comparison
- Cost comparison

C.3. Selection of generation dispatch used in DEV Power Flow Studies

The PJM RTEP Power Flow case for the year under study is the starting point for DEV Power Flow Studies. The generation dispatch in the PJM RTEP case is developed based on PJM's Study Methodologies as outlined in PJM's Manual 14B. DEV may modify this generation dispatch to develop a Base Power Flow case which is used as the starting point of DEV's Analysis to support PJM's RTEP Study Process. These modifications may include the following:

- Generating Units which have significant environmental limitations which severely limit the units availability in real time operation may be modeled as being off-line.
- Generating Units which have been identified in DEV's IRP Filings in Virginia/North Carolina as being "Potential" Generation Retirements may be modeled as being off-line.
- Known outages of a generating unit which are consistent with NERC TPL-001 selection criteria may be modeled as being off-line.

The base power flow dispatch provided to DEV in a power flow case which is used to analyze the reliability impact (Feasibility Study/System Impact Study) of generators in the PJM Generation Queue is typically modified by DEV. Since the case provided to DEV typically has all queue generation located on the DEV System as being off-line, DEV will modify the generation dispatch for power flow studies. Specifically, will turn on all higher order queue generators then the queue request under study as the base case condition for the generator under study. To account for this additional generation, generators located on the PJM System are proportional re-dispatched to account for this additional generation.

D. Transmission planning, system stability criteria

D.1. Introduction

There are many variables that affect the results of a stability study. These factors include but are not limited to:

- pre-fault and post-fault system configurations
- system load level and load characteristics
- generation dispatch patterns, unit dynamic characteristics and proximity to other generating units types and locations of system disturbances
- fault clearing time(s)
- the amount of flow interrupted as a result of switching out faulted elements
- level of detail and accuracy of available models/data

Many of these factors change in the operating area on a continuous basis. Every effort should be made to evaluate the most severe, yet credible/probable stability study scenarios in the planning area.

D.2. General criteria

Since 2005, PJM becomes the Transmission Planner (TP) for DEV. PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon, as well as the DEV's specific stability practices in ET Planning Criteria. Such stability analyses include but are not limited to:

- System impact stability study for Bulk Electric System[3] (BES) generation interconnection queue projects prior the in-service date of the projects
- Periodical Baseline, N-1-1 stability study for individual BES generation stations in

[3] NERC Bulk Electric System Definition Reference Document, link: https://www.nerc.com/pa/Stand/2018%20Bulk%20Electric%20System%20Definition%20Reference/BES_Reference_Doc_08_08_2018_Clean_for_Posting.pdf

compliance with the NERC TPL-001 standard

- Periodical Baseline, N-1-1 stability study for selected area using dynamic load model for voltage stability purpose in compliance with the NERC TPL-001 standard
- Periodical extreme events dynamic study for selected area for voltage stability purpose in compliance with the NERC TPL-001 standard
- Under frequency load shedding (UFLS) study for selected area periodically in compliance with the NERC and SERC PRC-006 standards

DEV ET Planning team supports PJM on their stability analysis responsibilities and conducts internal stability analyses. Stability study activities performed by ET Planning include but are not limited to:

- Assisting and reviewing PJM's system impact stability study for BES generation interconnection queue projects.

  Stability analysis is not required for units that are not part of the BES as defined by NERC. In PJM practice, generators rated 20 MVA or less in size and with aggregate plant capacity less than or equal to 75 MVA are not required to be studied in the system impact stability study process. DEV ET Planning determines whether to conduct the stability study for these units.

- Assisting, reviewing, and supporting PJM's stability study in compliance with the NERC TPL-001 standard
- Delayed protective relay tripping system stability analysis per the requests from DEV ET System Protection group
- Stability studies required in PJM Regional Transmission Expansion Plan (RTEP) projects (include but are not limited to projects involving FACTS devices)
- The substation physical security stability analyses in compliance with the NERC CIP-014 standard
- Special stability studies required by long-term (above 5 years) strategic planning projects

D.3. Study horizon

Stability studies performed for the near-term horizon (1-5 years) include but not limited to following types and can be implemented in a relatively short period of time:

- Transmission protection enhancement
- Generation protection enhancement
- Generation equipment enhancement
- Apply/modify/remove Remedial Action Scheme (RAS)
- Install/modify FACTS devices

- Establish operating restrictions for a contingency period covering forced or maintenance outages

For identified stability problems that cannot be remedied with the aforementioned solutions, new transmission infrastructure may be required to ensure stability for safe and reliable operation of the electric grid. In cases where a near-term horizon stability study indicates a potential correction that may require much longer lead time, a stability study for longer term would then be performed.

Stability studies performed for the long-term horizon (above 5 years) are determined by specific long-term strategic planning projects. The scope of the long-term studies is to better understand the grid performance of the DEV transmission system in a longer time scale and prepare for challenges with the rapidly changing generation and load environment and from the adoption of new technologies. Study results of such scenarios are carefully analyzed and the findings provide important supplemental information to the development of DEV's transmission expansion plan.

D.4. Dynamics data collection

PJM will collect dynamic data and submit to Multi-Regional Modeling Working Group (MMWG) as outlined in the Eastern Interconnection Reliability Assessment Group (ERAG) MMWG Procedural Manual.

Dominion Energy Electric Transmission Planning is responsible for submitting dynamic data to PJM for Transmission Owner equipment with dynamic characteristics (e.g. FACTS devices) and dynamic loads data.

D.5. Stability study case development

Planning area studies for stability analysis are performed using estimated snap-shots of the expected system operating conditions for the study period selected. The power flow base cases that match dynamics data for the Eastern Interconnection are prepared by the Multi-regional Modeling Working Group (MMWG) for selected years on an annual basis.

For individual stability analysis, the analysis performer is responsible to work with DEV ET Planning modeling team to develop most appropriate load flow and dynamic cases for the study. Such model development activities may include:

- Adjustment to the model topology to include transmission/generation projects completed before the targeting study date
- Adjustment to area loads and generation re-dispatch schemes to match the targeting study scenario
- Adjustment to dynamic model parameters and other system assumptions per the specific study scope

After the dynamics model setup, an unperturbed dynamic simulation for 20 -30 seconds is required to ensure that the steady-state stability is maintained.

D.6. Selection of generation dispatch

The economic dispatch used in internal power flow base cases may not represent conditions which could pose a stability risk. Therefore, the power flow cases may be stressed to test the area or generation under study. For example, increased transfers near generating facilities can have an adverse impact on transient stability and therefore need to be accounted for when creating stressed yet credible system dispatches for the stability studies.

Unit dispatch for transient stability studies also differs from the conventional power flow analysis. Units in the study region are generally dispatched to maximum real power output (Pmax), and at leading power factor at the low side of the GSU provided that the equipment voltage limits are not violated. Specifically, units under study and electrically close that fall within the study region[4] should be dispatched to absorb approximately 50% of the minimum reactive capability (Qmin) without violating the terminal voltage limits (generally 0.95 pu).

D.7. Selection of contingencies

Contingency categories and simulation specifications are based on Table 1 of NERC Reliability Standard TPL-001.

For generation interconnection system impact study and TPL-001 compliance stability study, DEV ET Planning adopts the same contingency criteria and margins as used in PJM stability study.[5] For other stability analyses initiated by ET Planning, the analysis performer is responsible to select the most appropriate contingency criteria and margins.

D.8. What to look for in study results

Checks are performed to make sure all on-line units initialize properly without any error messages.

Checks are performed to make sure the system is stable within the acceptable operating criteria:

- Acceptable Transient Voltage Recovery: When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics. Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 p.u. after 2.5 seconds. The transient voltage recovery criteria should be satisfied at BES buses.
- Acceptable Damping: Following the disturbance, the oscillations of the monitored parameters display positive damping. The damping ratio should reach 3% or better for

[4] Engineering judgment must be applied in selecting the generators that *electrically close* to unit(s) under study.
[5] PJM Manual 14B: PJM Region Transmission Planning Process Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

inter-area oscillations and 4% or better for local mode oscillations.

Solutions identified in section D3 are considered for situations where transient voltage or oscillation damping is not met, or if transient stability is not maintained. If the inter-area oscillations have an unacceptable damping ratio and other entities' units are found to be participating significantly, then it may require a joint study between the affected parties. N-1-1 contingencies with no re-dispatch are considered to ensure transient stability is maintained with positive damping. If the oscillation damping is positive but does not meet the criteria above, operation restriction may be applied to ensure sufficient oscillation damping for both local and inter-area modes of oscillations.

For system conditions and selected contingencies that results in generator transient instability, additional analysis is performed to quantify the risk of cascading events and potential for blackout conditions. Cascading failure analysis will consider a risk-based study of the loss of the generating unit based on expected protection and control as well as unexpected tripping. Depending on the size and expanse of the affected area, other solution options, operating restrictions, or transmission investments may be considered.

Since the transmission planning studies are performed for an estimated operating condition for a future date, the post disturbance thermal loading and voltage levels may vary widely when real disturbance occurs. This is because the load, generation dispatch and available reactive resources in real time may be quite different than the ones studied in planning area. For this reason, the thermal limits and voltage conditions should be checked using the real-time contingency analysis tool.

D.9. Implementation procedure

Stability analysis may warrant corrections or additional requirements in order to meet the stability criteria listed in this document. The implementation procedure for such items depends on the type of corrections warranted and the nature of installation. The following is a general guideline for Transmission Planning to get such fixes implemented.

D.9.1. For existing installations

- Corrections related to transmission fault clearing times near generating stations that can be resolved by changes to existing relay set points shall be communicated to DEV ET System Protection group for implementation. PJM should also be informed as to the results of this analysis.
- A Capital project shall be generated for corrections related to transmission fault clearing times near generation stations that require baseline improvements such as new or additional equipment. All Capital projects shall first be validated, approved and assigned cost and construction responsibility by the PJM Regional Transmission Expansion Planning (RTEP) process.
- Output restrictions and/or unit trip(s) for the next pending contingency

condition identified by DEV in routine planning studies, will be communicated to the SOC. In turn, the SOC shall inform PJM for implementation as appropriate.

- In case of scheduled maintenance or construction outages, the results/recommendations shall be conveyed to the person through whom the stability analysis request came to the stability engineers. For example, if a Project Manager requests such analysis to the load Planning Engineer, the stability engineer shall forward his analysis to the load Planning Engineer. If SOC requests such analysis, the results/recommendations shall be forwarded to SOC which in turn shall inform PJM for implementation as appropriate.

D.9.2. For new installations or capacity additions

New generating resources are studied as part of the PJM Generation Interconnection Queue process. PJM shall document the fault clearing time requirements and/or any additional protection requirements in its Impact Study report. PJM shall also communicate the requirements on the generation side to the GO requesting the Interconnection in PJM Queue. For the transmission related requirements, DEV shall communicate these to the Substation Engineering group for design and implementation.

E. Nuclear plant interface coordination

E.1. Introduction

Nuclear power plants have special needs for backup station service not found in other plants. In order to safely shut down a nuclear unit, the station service must have an adequate supply of power under tight voltage tolerances to the safety systems. Although nuclear plants have diesel generators as a backup supply, their preferred power source is the transmission grid. This allows multiple levels of redundancy which is the hallmark of the nuclear plant's endeavor to the highest level of safety.

E.2. NRC regulations

The Federal Nuclear Regulatory Commission (NRC) lays out certain regulations on the design and operation of Nuclear Plants. **Appendix A of Regulation 10 CFR 50** "General Design Criteria for Nuclear Power Plants" states:

> *"Criterion 17--Electric power systems. An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other*

vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies."

The above regulation General Design Criterion 17 is often abbreviated "GDC-17."

E.3. Design requirements

PJM and Dominion Energy Electric Transmission Planning will design the system to meet the GDC-17 requirements. In order to provide adequate voltage to safety systems, the Nuclear group periodically provides Nuclear Plant Interface Requirements (NPIR) to Dominion Energy Electric Transmission. Dominion Energy transmission planners should consult the latest version of applicable Interface Agreements between Dominion Energy Electric Transmission and the nuclear plants for applicable normal and emergency voltage limits, voltage drops and contingency scenarios.

Because emergency systems require adequate voltage immediately following an event, transmission LTC's should be locked post-contingency.

For violations of the NPIRs, the transmission planner will contact the GDC-17 coordinator for Electric Transmission Planning. PJM/Dominion Energy Electric Transmission Planning will notify Dominion Energy Nuclear of any NPIR criteria violations. Transmission study criteria violations based on standard PJM/Dominion Energy criteria testing will be handled by the procedures described in the PJM agreements and manuals. For study violations that are beyond applicable PJM criteria, Dominion Energy Nuclear will determine if any further action is required and respond to Dominion Energy Electric Transmission Planning. Dominion Energy Electric Transmission Planning will work with PJM to resolve concerns identified by Dominion Nuclear.

For contingencies more severe than those within the NPIRs, standard planning voltage range criteria will be applied.

E.4. Underfrequency studies

The underfrequency load shed program (UFLS) should be designed to coordinate with station underfrequency trip settings. The North Anna reactor coolant pump (RCP) is set to trip at 56.55 Hz with a time delay of 100 milliseconds. The Surry reactor coolant pump (RCP) is set to trip at 58.05 Hz with a time delay of 100 milliseconds.

E.5. Angular stability studies

Angular stability studies are performed on nuclear plants using the standard methodology used for any synchronous machine. The results of these studies should be forwarded to Nuclear Engineering.

E.6. System analysis protocol

The Nuclear Switchyard Interface Agreement System Analysis Protocol (CO-AGREE-000-IA1-4 or its successor) outlines the types and frequency of studies which may be performed in support of the nuclear plant. It also specifies the type of communications necessary and the frequency of the analysis. In order to show compliance with NERC Standard NUC-001-2 (or its successor), the GDC-17 coordinator shall retain evidence of communications with the appropriate nuclear contacts.

E.7. Changes to the system

The NERC standard NUC-001-2, R8 states that the "…Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, protection systems, or capabilities that may impact the ability of the electric system to meet the NPIRs."

F. References

- NERC Planning Standard TPL-001
- NERC PRC Standards 12 - 17
- Transmission System Performance SERC Supplement
- NERC Reliability Standard NUC-001
- Nuclear Switchyard Interface Agreement CO-AGREE-000-IA1
- Nuclear Switchyard Interface Agreement System Analysis Protocol CO-AGREE-000-IA1-4

- PJM Manual 39 – Nuclear Plant Interface Coordination
- Manual 14B – PJM Region Transmission Planning Process

G. Abbreviations & definitions

- **AAR** - Auction Revenue Rights (see PJM Manual 06 – Financial Transmission Rights for more details)
- **ANSI** - American National Standards Institute
- **ERAG** - Eastern Interconnection Reliability Assessment Group
- **FCITC** - First Contingency Incremental Transfer Capability
- **Good Utility Practice** - Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.
- **GSU** - Generator Step-up Transformer
- **IEEE** - Institute of Electrical and Electronic Engineers
- **MMWG** - Multi-Regional Modeling Working Group
- **NERC** - North American Electric Reliability Corporation
- **POI** - Point of Interconnection
- **RTO** - Regional Transmission Organization
- **PSS** - Power System Stabilizer
- **SERC** - SERC Reliability Corporation

H. Revision History

Revision Date	Revision #	Description	Revised By	Effective Date
08/24/1999	0.0*	Original document created to meet the requirements of NERC Planning Standard I.C.S1.M1.	ET Planning staff	08/24/1999
05/01/2001	1.0*	See Details for Revision 1.0 below	ET Planning staff	05/01/2001
09/07/2005	2.0*	See Details for Revision 2.0 below	ET Planning staff	09/07/2005
05/29/2007	3.0*	See Details for Revision 3.0 below	ET Planning staff	05/29/2007
12/22/2009	4.0*	See Details for Revision 4.0 below	ET Planning staff	12/22/2009
12/22/2011	5.0*	See Details for Revision 5.0 below	William F. Bigdely	12/22/2011
10/10/2012	6.0	See Details for Revision 6.0 below	William F. Bigdely	10/10/2012
11/22/2013	7.0	See Details for Revision 7.0 below	William F. Bigdely	11/22/2013
03/31/2014	8.0	See Details for Revision 8.0 below	William F. Bigdely	03/31/2014
07/16/2014	9.0	See Details for Revision 9.0 below	William F. Bigdely	07/16/2014
01/09/2015	10.0	See Details for Revision 10.0 below	William F. Bigdely	01/15/2015
03/26/2015	11.0	See Details for Revision 11.0 below	William F. Bigdely	03/27/2015
12/15/2015	12.0	See Details for Revision 12.0 below	William F. Bigdely	01/01/2016
05/15/2017	13.0	See Details for Revision 13.0 below	William F. Bigdely	06/01/2017
03/29/2018	14.0	See Details for Revision 14.0 below	William F. Bigdely	04/01/2018
12/13/2018	15.0	See Details for Revision 15.0 below	William F. Bigdely	01/01/2019
03/11/2019	16.0	See Details for Revision 16.0 below	William F. Bigdely	03/15/2019
03/10/2020	17.0	See Details for Revision 17.0 below	David C. Witt	03/24/2020
06/22/2020	18.0	See Details for Revision 18.0 below	David C. Witt	07/01/2020
02/22/2021	19.0	See Details for Revision 19.0 below	Hamidreza Sadeghian	04/01/2021
03/03/2022	20.0	See Details for Revision 20.0 below	Mark Gill	04/01/2022
02/16/2023	21.0	See Details for Revision 21.0 below	Amirreza Sahami	04/01/2023

*For these revisions, the planning guideline was an attachment within the DEV facilities connection requirements document. Associated comments for these revisions do not necessarily apply to the contents of the planning guideline specifically.

Details for Revision 1.0

- Revised to include information regarding Dominion's generation interconnection procedures/process

Details for Revision 2.0

- Revised to reflect transition from old NERC Planning Standards to NERC Reliability Standards, including changing the naming convention of all referenced standards throughout the document.

Details for Revision 3.0

- Revised to reflect the following:

- Updates to NERC Reliability Standards
- Dominion's PJM Membership
- References to new SERC regional studies processes

Details for Revision 4.0

- Revised to reflect the following :
    - PJM Generation Queue Changes Section 4
    - General Revisions all sections

Details for Revision 5.0

- Revised the following:
    - Section 2.12: Clarified content regarding synchronizing of facilities.
    - Exhibit A: Changed loading criteria to not exceed emergency rating of transmission facility.
    - Various errata changes.

Details for Revision 6.0

- Overhaul and expansion of entire Planning Criteria.
- Document previously called "Transmission Planning Guidelines"

Details for Revision 7.0

- Updated to include future reference to TPL-001-4 (R1 and R7 NERC enforcement date of 01-01-2015)
- Updated titles for approval process
- Various errata changes

Details for Revision 8.0

- Expanded description for Section G.1. TAPPING LINE BELOW 100 MW LOAD to emphasize the requirement of a fused bypass arrangement.
- Recreated diagrams throughout for consistency of style.

Details for Revision 9.0

- Added section C.2.8 - End of life criteria
- Reformatted headers to improve PDF navigation via bookmarks.

Details for Revision 10.0

- Clarifications and annual review.
- Reformatted approval area and moved to title page.
- Reformatted Revision History and moved to end of document (Section J).
- Modified throughout to reflect NERC Reliability Standard TPL-001-4, including replacement of Tables 1A and 1B and deletion of "Category D Multiple Testing Requirements" (previously Section C.2.7 in Revision 9.0 document).

- Section C.2.6 Radial lines: Expanded to introduce new criteria and metrics.
- Section C.2.7 Network transmission lines – Limitations on direct-connect loads: Inserted new section.
- Section D.4 Study cycle – Clarified that PJM (not DEV) performs simulations to cover all generating plants over a three-year study cycle (not five-year).
- Section G: Modified electrical arrangements and clarified lines of demarcation.

Details for Revision 11.0

- Section C1, Table 1A Notes – Added Note “C”
- Section C1, Table 1B Notes – Added Note “G”; re-numbered other notes to differentiate from Table 1A [Note G became Note I in v15]
- Section D7 Selection of generation dispatch – Rephrased the content to improve clarity.

Details for Revision 12.0

- Changed references of Special Protection System (SPS) to Remedial Action Scheme (RAS).
- Tables 1A and 1B: Removed references to DC line (does not apply to Dominion), and
- Table 1A, Note B and Table 1B, Note F: Clarified “may NOT be required if the loss of consequential and non-consequential load up to 300MW achieves a return to the STE rating.”
- Section E.3. Updated NPIR Limits.
- Former Section F (Transmission Line Connections – Generation) and former Section G (Load Criteria – End User) have been removed from this document and integrated into the Facility Interconnection Requirements as Sections 5 and 6.
- Section G Abbreviations & definitions: Added definition of “Good Utility Practice”.

Details for Revision 13.0

- Revised references for new Dominion Energy corporate identity.
- Section C.1. Added Table 1C Steady-State Performance EXTREME Events and Dominion Energy CRITERIA, and associated notes; refined notes for Tables 1A and 1B.
- Added Section C.2.8. Substation – Limitation on direct-connect loads.

Details for Revision 14.0

- Clarified that some notes to Tables A, B and C are “Dominion Energy” notes.
- Edited Dominion Energy Note “B” for Table 1A and Note “F” for Table 1B to remove phrase “and non-consequential” [load]. [Note F became Note H in v15]
- Edited Dominion Energy Note “C” for Table 1A and Note “G” for Table 1B to refer to new section C.2.1.3. [Note G became Note I in v15]
- Added Section C.2.1.3 - Critical stress case development and studies

Details for Revision 15.0

- Reviewed to ensure alignment with Facility Interconnection Requirements, v15, effective 1/1/2019.
- Tables 1A, 1B, 1C: Added new notes to Tables 1A and 1B, requiring re-labeling of notes in Tables 1A, 1B and 1C as follows:

Previously	Now
A	**A**
B	**B (edited)**
-	**C (NEW)**
C	**D**
-	**E (NEW)**
D	**F**

Previously	Now
E	**G**
F	**H**
G	**I**
-	**J (NEW)**
H	**K**
I	**L**

Previously	Now
J	**M**
K	**N**
L	**O**
M	**P**
N	**Q**

- Section C.1. Planning principles and standards - Simplified reference to Nuclear generation re-dispatch.
- Section C.2.9. End of life criteria - Edited discussion and list of factors considered.
- Section C.3. Selection of generation dispatch used in DEV Power Flow Studies - New section.
- Section E Nuclear plant interface coordination:
  - E.3. Design Requirements – Removed tables of NPIR voltage limits, voltage drops, and contingency scenarios.
  - E.7. Changes to the system – Simplified content to contain only the NUC-001-2, R8 quotation.

Details for Revision 16.0

- Table 1A, Note B: Deleted specific reference to 230 kV (table applies to several voltages).
- Table 1B, Notes F & G: Removed specific references to 500 kV (500 kV is inherent to this table).

Details for Revision 17.0

- Updated dates, names and revision number.
- Tables 1A and 1B – Added contingency for Category P4, Event 6
- Section C.1 Planning principles and standards – Added language describing N-1-1 contingency analysis.
- Section C.2.6. Radial transmission lines – Edited discussion.
- Section C.2.9. End of life criteria – Removed evaluation of lines operating below 500kV and edited assessment language.
- Section D Transmission planning, system stability criteria – General update of this section including language expanding the stability study horizon beyond 5 years to accommodate longer term strategic projects.
- Section F – Updated to include reference to PRC Standards 12 -17.

Details for Revision 18.0

- Table 1A – Decreased the high voltage limits for 138kV lines.
- Table 1B – Revised the high voltage limits for 500kV and above lines.
- Table 1C – Revised Note “Q” Extra High Voltage (EHV) limit to 109.6%.

Details for Revision 19.0

- Updated Signature Page.
- Section C.1 Planning principles and standards – Revised time frame of system adjustments.

- Table 1A – Removed the Note "A", "B", and "C" and set the Thermal Limits to 100% of Short Term Emergency (STE). Note C added for system adjustments at initial condition in P3 and P6. In addition, system reinforcements for load loss more than 300 MW are indicated.
- Table 1B – Removed the Note "F", "G", and "H" and set the Thermal Limits to 100% STE. Note F added for system adjustments at initial condition in P3 and P6. In addition, system reinforcements for load loss more than 300 MW are indicated.
- Table 1C – Changed the Note References.

Section C.2.2. Added footnote for DEV criteria on Generation Deliverability.

Details for Revision 20.0

- Updated Signature Page.

Details for Revision 21.0

- Updated Signature Page.
- Minor typos and grammatical edits through the entire document.
- Section C.1., Table 1A, Table 1B: P5 is updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section C.1., Note 13 is updated to include future reference to TPL-001-5.1 (Effective date is 07/01/2023).
- Section C.2.6 Radial transmission lines criteria is modified to address wider range of situations.