DUKE ENERGY CAROLINAS TRANSMISSION SYSTEM PLANNING GUIDELINES

Transmission Planning

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I. SCOPE

This document was designed to provide a summary of the fundamental guidelines used by Transmission Planning employees to plan Duke Energy Carolinas' (DEC) 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV transmission systems.

Any reliable transmission network must be capable of moving power throughout its system without exceeding voltage, thermal and stability limits, during both normal and contingency conditions. These guidelines are designed to help Transmission Planning employees identify potential system conditions that require further study. **It does not provide criteria for which absolute decisions are made regarding transmission system improvements**. Duke Energy Carolinas retains the right to amend, modify, or terminate any or all of these guidelines at its option.

II. TRANSMISSION PLANNING OBJECTIVES

The guidelines in this document are formulated to meet the following objectives:

- Provide an adequate transmission system to serve the network load of the Duke Energy Carolinas service territory.

- Balance risks and expenditures to ensure a reliable system while maintaining flexibility to accommodate an uncertain future.

- Maintain adequate transmission thermal capacity and reactive power reserves (in the generation and transmission systems) to accommodate scheduled and unscheduled transmission and generation contingencies.

- Achieve compliance with the NERC and SERC Reliability Standards that are in effect.

- Adhere to applicable regulatory requirements.

- Minimize losses where cost effective.

- Provide for the efficient and economic use of all generating resources.

- Provide for comparable service under the Duke Energy Carolinas, LLC FERC Open Access Transmission Tariff.

- Satisfy contractual commitments and operating requirements of inter-system transactions.

III. PLANNING ASSUMPTIONS

A. Load Levels

- Summer Peak (for current year and next 10 years)
- Winter Peak (for current year and next 10 years)
- Spring Valley (for current year and next 2 years)
- Loads plus losses at the transmission level will be scaled to match the system forecast for each load level. When conditions warrant, additional cases may be generated to examine the impact of other load levels.

B. Generation

1. Dispatch

Generation patterns may have a large impact on thermal loading levels and voltage profiles. Therefore, varying generation patterns shall be examined as a part of any analysis. Generators with confirmed, firm transmission reservations or designated as network resources are considered as being available for dispatch. Units serving native load are economically dispatched for normal and contingency conditions. Normal outages for maintenance, forced outages, and combinations of normal and forced outages are modeled. Generating units are modeled at their expected seasonal continuous capability. Based on operating experience to date, transmission connected solar PV generation (without storage capability) is typically dispatched at 80% output coincident with our summer peak and 0% output coincident with our winter peak load levels. If operational data from a site indicates a large variance from these assumptions, then the site may be dispatched at a different output. If available, battery storage is dispatched to achieve a combined output up to 100% PV output coincident with our summer peak and 100% battery output only coincident with our winter peak.

2. Voltage Schedules

An optimal power flow program is used to determine the voltage schedules for major system generating units. The schedules are tailored for season and load level to meet system reactive power requirements.

3. Reactive Capability

Generator reactive capability data is included in the base power flow models so the impact of reactive power available from generators can be reproduced in the system model. All generating units are modeled with the reactive capability available at their maximum MW output across all MW output levels from zero to maximum. This assumption provides the actual reactive capability to all units dispatched at their maximum output and provides a conservative reactive output for any unit dispatched below their maximum output.

C. Power Transactions

Long-term firm transactions between control areas are included in the appropriate power flow base cases and shall be consistent with contractual obligations. For an emergency transfer analysis, generation is reduced in a manner that will cause stress on the system.

DEC participates in several reliability groups that perform transfer studies on a regular basis: SERC Long-Term and Near-Term Power Flow Working Groups, NCTPC (North Carolina Transmission Planning Collaborative), CTCA (Carolinas Transmission Coordination Arrangement), SERTP (Southeastern Regional Transmission Planning).

D. Equipment Ratings

The methodologies used to rate transmission facilities encompass all components (e.g., transformers, line conductors, breakers, switches, line traps, etc.) from bus to bus. Wind speed and angle, ambient temperature, acceptable operating temperatures, as well as other factors, are used in determining facility ratings. All facilities are composed of eight ratings reflecting the following capabilities for both summer and winter seasons:

- continuous
- long-term emergency (1 year)
- 12-hour emergency
- 2-hour emergency

E. Nominal Voltages

Nominal voltages on the DEC system are 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV. Additional nominal voltages of 138 kV and 115 kV are utilized for some of DEC's interconnections with other utilities.

F. Common Right-of-Way

Part of the judgment used for any analysis is the definition of line outages on a common right-of-way. Clearly, there are situations where multiple lines may leave a station in a similar direction and along a common corridor for some short distance. While there are no clear-cut rules, the length of exposure of a common right-of-way and the criticality of the circuits involved must be considered when defining which rights-of-way should be studied.

IV. STUDY PRACTICES

DEC conducts transmission planning studies including, but not limited to:

- Screening of Voltage Guidelines
- Screening of Thermal Guidelines
- Grid Voltage Study For Nuclear Loss-Of-Cooling Accident (LOCA)
- Spare Transformer Study
- Transformer Tertiary Study
- Optimal Power Flow Studies For Generator Voltage Schedules And Capacitor Additions
- Angle and Voltage Stability Analyses
- Power Transfer Studies
- System Impact Studies
- Generation Interconnection and Affected System Studies
- Fault Duty Analyses
- Miscellaneous Losses Evaluation
- Facilities Adequate Evaluations
- Severe Contingency Studies

During the course of transmission planning activities, the identification of a System Operating Limit (SOL) or an Interconnection Reliability Operating Limit (IROL) in the planning or operating horizon is possible. SOL's and IROL's are defined as:

SYSTEM OPERATING LIMIT (SOL) - The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-contingency stability limits)
- Voltage Stability Ratings (Applicable pre- and post-contingency voltage stability)
- System Voltage Limits (Applicable pre- and post-contingency voltage limits)

INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL) - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.

Transmission Planning activities develop Corrective Actions Plans to address possible SOL or IROL exceedances in the Near-Term Transmission Planning Horizon that are annually shared with System Operations Engineering (as DEC's Transmission Operator and Reliability Coordinator) in accordance with FAC-014-3 via a Planning Assessment document. If a transmission planning activity identifies a SOL or IROL may be exceeded in the operating horizon, System Operations Engineering should be immediately notified. The SOL or IROL information shall also be provided to adjacent Planning Authorities and adjacent Transmission Planners. In accordance with FAC-003-4 Applicability – Transmission Facilities 4.2.2, if an overhead transmission line operated below 200 kV is identified as an element of an IROL, DEC's Vegetation Management must be notified. SOL or IROL limit violations identified in the planning horizon should be corrected and/or mitigated in advance of the operating horizon.

V. PLANNING GUIDELINES

Transmission Planning is charged with planning the transmission system (500 kV, 230 kV, 161 kV, 100 kV, 66 kV, 44kV) and the system interconnections, as well as consulting in planning the distribution system (34.5 kV and below). Voltages and thermal loadings that violate the following guidelines will result in further analyses. Studies of the transmission system give consideration to the effect we may have on the planning and operation of neighboring utilities as well as the effect they may have on our system. Studies include an evaluation of our ability to support our self-supply and import/export commitments under the Carolinas Reserve Sharing Group (CRSG) agreement. CRSG members are DEC, DEP, DESC, and SCPSA.

As a part of the NERC Reliability Standards, utilities are charged with planning their system in a manner that avoids uncontrolled cascading beyond predetermined boundaries. This is to limit adverse system operations from crossing a control area boundary. To this extent, DEC participates in several regional reliability groups: VACAR (Dominion Virginia Power and SERC East Subregion of SERC), SERC Long-Term and Near-Term Power Flow Working Groups, NCTPC (North Carolina Transmission Planning Collaborative), CTCA (Carolinas Transmission Coordination Arrangement), SERTP (Southeastern Regional Transmission Planning). Each of these reliability groups evaluates the bulk transmission system to ensure: 1) the interconnected system is capable of handling large economy and emergency transactions, 2) planned future transmission improvements do not adversely affect neighboring systems, and 3) the interconnected system’s compliance with selected NERC Reliability Standards.

Each of these study groups has developed its own set of procedures that must be followed. These study groups do not have as one of their objectives the analysis and planning for any one individual system. The main objective of these groups is to maintain adequate transmission reliability through coordinated planning of the interconnected bulk transmission systems.

In addition to these regional reliability studies, DEC conducts its own assessments of transmission system performance. While these assessments are typically focused on the DEC system, they cannot be conducted without consideration of neighboring systems.

The voltage and thermal guidelines for the transmission system under normal and contingency conditions are described in Section A and Section B, respectively. A description of the contingencies studied as part of any voltage or thermal evaluation is provided in Section C.

A. Voltage

Bus voltages are screened using the Transmission System Voltage Guidelines below and reviewed against historical operating data to determine the need for corrective actions. These guidelines specify minimum and maximum voltage levels, the allowable voltage deviation following P1, P2, P3, P4-1 and P5-1 contingency conditions. For all other P4 and P5 events as well as P6 and P7 events voltages can exceed these limits; however, these limits will be used to conservatively flag potential voltage violations for a further evaluation. Acceptable performance for these events will be determined by the extent of Non-Consequential Load Loss and cascading.

Absolute Voltage Limits are defined as the upper and lower operating limits of each bus on the system. The absolute voltage limits are expressed as a percent of the nominal voltage. All voltages should be maintained within the appropriate absolute voltage bounds for all conditions.

Voltage Regulation is defined as the difference between expected maximum voltage and minimum voltage at any particular delivery point. The voltage regulation limits are expressed as a percent of the nominal voltage and are defined for both normal and contingency conditions. Voltage regulation for delivery point voltages should not exceed the guidelines.

Contingency Voltage Drop is defined as the maximum decrease in voltage due to any single contingency.

161 kV, 230 kV, & 500 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits Minimum	Absolute Voltage Limits Maximum	Maximum Allowable Contingency Voltage Drop
161	95%	105%	5%
230	95%	105%	5%
500	100%	110%	5%

44 kV, 66 kV, & 100 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits Minimum	Absolute Voltage Limits Maximum	Voltage Regulation Normal	Voltage Regulation Contingency
44	94%	109%	8.5%	10%
66	94%	109%	8.5%	10%
100	95%	107%	6%	7%

Autotransformer voltage limits are based on the secondary tap setting. The minimum voltage is 95% of the tap voltage and the maximum voltage is 105% of the tap voltage under full load and 110% of the tap voltage under no load. Thus, the voltage limits for transformers vary with both loading and tap setting. The secondary tap on most of DEC's 220/100 kV autotransformers is 100 kV. The one exception is AT-2 at Pisgah Tie; it is set at 95 kV. This implies a maximum voltage of 99.75 to 104.5 kV, depending on loading. The following table shows what stations have 220 kV transformers and how many there are at each station.

220/100 kV Autotransformers

Station	Number of 220 kV Autotransformers	Bank #
Beckerdite	1	3
Eno	1	4
Morning Star	2	3, 4
N. Greenville	2	1, 2
Pacolet	1	1
Pisgah*	1	2

*Pisgah AT-2 is on the 95 kV tap.

Nuclear voltage limits are based on the design of electrical auxiliary power systems within the plants and Nuclear Regulatory Commission (NRC) requirements. There are two sets of these limits: minimum and maximum generator bus voltage limits and minimum grid voltage limits.

B. Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

a) Under normal conditions, no facility should exceed its continuous thermal loading capability.
b) With a transmission contingency having an expected duration of less than 12 hours (line outage or single-phase transformer outage where spare is available), no facility should exceed its 12-hour emergency loading capability.
c) With a capacitor, transformer (three phase or single phase with no spare) or generator contingency having an expected duration of more than 12 hours, no facility should exceed its long-term emergency loading capability.

C. Selected Contingencies

The planning studies for the transmission system are performed for normal and contingency conditions in accordance with TPL-001. The applicable thermal and voltage guidelines should not be violated for either normal operations or under the contingency conditions required to be studied.

Several 230 kV tie stations on the DEC system have incomplete Double bus or Breaker-and-a-half designs. Thus, abnormal single contingency configurations can result. To properly screen for violations of the guidelines, the following table indicates the transformers that should be evaluated for abnormal single contingencies. Breaker contingencies must be evaluated based on the individual configuration.

230 kV Tie Stations With Abnormal Single Contingency Configurations

Tie Station	Outaged facilities for 230 kV line fault	Outaged facilities for 230/100 kV autotransformer fault
Bush River	The line and transformer	The transformer and a line
Hodges	The line	The transformer and a line
Lakewood	The line and transformer	The transformer and a line
McDowell	The line	The transformer and a line*
Morning Star	The line	The transformer and possibly a line *
Peacock	The line	The transformer and a line
Shady Grove	The line	The transformer and tap line
Tuckasegee**	The line	The transformer and a line
Woodlawn	The line and transformer	The transformer

* Depends on which 230/100 kV transformer experiences the fault.

** 230/161 kV transformer

D. Miscellaneous

1. Spare Transformer Policy

This policy is reviewed periodically to account for changes in failure rates, transformer lead times, and outage costs. Currently, the following number of spares should be available:

Spare Transformer Requirements

Type of Transformer	# of Spares
230/100/xx kV Autotransformer	4
30/40/50 MVA 3 phase 100/44 kV	0
20/27/33 MVA 3 phase 100/44 kV	1
12/16/20 MVA 3 phase 100/44 kV	1

2. Transformer Tertiary Study

This study determines the minimum number of tertiaries required in service to operate the system reliably. Having only the required number of tertiaries in service reduces failures from detrimental in-service events like faults.

3. Optimal Power Flow (OPF) Studies

OPF studies are conducted to determine the seasonal generator voltage schedules and support reactive power planning. OPF study results are utilized to minimize system losses by optimizing the use of existing VAR resources and planning additional future resources.

4. Stability

a) Angle

DEC performs stability analyses on large generating units as major generation or transmission changes occur on the system and as required by the NERC Reliability Standards. In addition, stability analysis will be performed for the nuclear plants in compliance with Nuclear Regulatory Commission requirements. These studies assess the ability of the interconnected network to maintain angular stability of the generating units under various contingency situations. Many different contingencies are considered, and the selection is dependent on the type of study and location within the transmission system. The stability of the DEC system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC Reliability Standards.

b) Voltage

An important part of preventing cascading outages is ensuring that voltage collapse will not cascade for the applicable contingencies defined in the NERC Reliability Standards.

Voltage stability analyses are performed using complex load models for loads in DEC and neighboring systems. The DEC system is studied on system peak and shoulder conditions applying various single and multiple contingencies to detect voltage collapse for single contingencies, for multiple element contingencies, and delayed clearing contingencies.

The corrective measures such as faster relaying, transmission upgrades, or unit tripping are determined on an individual basis after considering economics, probability of occurrence, and severity of the disturbance.

5. Power Transfer Studies

Power transfer studies may be conducted as a part of a load addition, a facility addition or upgrade analysis, as a part of a system impact study, or with the regional study groups to ensure system reliability. The Available Transfer Calculation (ATC) methodology document explains how to algebraically account for setting aside of Transmission Reliability Margin (TRM) associated with CRSG commitments.

6. Impact Study

Impact studies are performed to identify any problems associated with a requested/proposed system change. The following analyses are performed if necessary:

A. Power Flow Analysis
A power flow analysis will be performed to determine any violations of the planning guidelines due to the addition of the request. Projects that will be accelerated by the request will be identified as well as projects that will be needed to correct violations prior to implementation of the request.

B. Transfer Analysis
A transfer analysis will be performed to determine the impact on the bulk power system and to assess the changes that will occur in other areas resulting from the request.

C. Stability Analysis
A stability analysis will be performed to determine any violations to planning guidelines.

D. Fault Analysis
A fault analysis will be performed to determine information necessary for sizing equipment.

E. Other analyses as required for a particular request.

7. Fault Duty

Fault duty studies are performed to determine the available fault current for each transmission system (500, 230, 161, 100, 66, and 44 kV) breaker location. Aspen's Breaker Rating Module (BRM) program that resides within the software is used to check if the fault current capacity of the existing breakers is being exceeded. Action is taken to upgrade a breaker when studies indicate the fault current is 97% or greater of the breaker's rating. Fault duty studies are also used to assist in sizing the interrupting capacity of new breakers being installed on the system. When major system changes or additions are to be implemented, a BRM study is performed for both the existing and future state system configurations to determine the impact on the Transmission System and if any breaker's capacity will be exceeded.

<u>Network</u>
Faults are evaluated for each breaker location to find the highest available fault current for the following conditions:

- single phase to ground fault
- three phase to ground fault
- fault resistance assumed to be zero
- location of fault assumed to be at terminals of the breaker in question
- all breakers at a bus in service
- breakers taken out, one at a time
- line mutual impedance included
- all generation units included
- adjacent system fault contributions included
- Linear network solution is used to determine the pre-fault voltage.
- ANSI X/R ratio is used in these calculations
- Further details available in Aspen Oneliner's braker rating module application guide

The maximum calculated fault current at each breaker location and the associated breaker fault duty capability are compared to determine where violations of the breaker rating exist.

<u>Radial</u>

Fault duty for radial locations is calculated using fault duty at the associated network bus with the impedance of the radial line segment included.

8. Miscellaneous Losses Evaluations

Various equipment and system loss evaluations are performed to aid in the selection of equipment, to meet contractual obligations and to compare system configurations.

9. Facilities Adequate Reviews

Facility Adequate Reviews are performed when a customer requests a change in contract MW. The existing facilities are evaluated for the proposed change in load and a determination is made concerning any necessary improvements.

10. Voltage and Load Studies

Voltage and Load Management (V&L) is primarily responsible for monitoring and correcting voltage level concerns as it applies to company transmission assets. Specifically, electrical models are created studying voltage impacts, loading patterns and pending limit concerns as it pertains to our connected customer deliveries. This requires the review and implementation of regulatory policy in maintaining voltage levels mandated by state regulatory commissions through the use of increasing system power factor and the utilization of voltage regulation methods. V&L focuses on those customers served from the 161, 100, 66, and 44 kV electrical systems. In addition, V&L have input in the following:

1) New Station Commissioning
2) Station Rebuilds
3) System Capacity Changes
4) Planned Outages for Stations or Lines
5) Capacitor Install and Re-sizing
6) Proposed KW Contract changes and New KW Contracts Proposals
7) Installation of Portable Capacitors and Transformers
8) System Consultant to System Operations, Distribution and Business Stakeholders
    a. Transmission Planning
    b. Account Management
    c. Project Management
    d. Distribution Planning
    e. Asset Management
    f. Project Engineering

Requests for V&L services are initiated through Planned Study of Projects, Substation Engineering Projects, and/or Walk in or Phone Requests. The process that initiates portable capacitors are as follows:

1) Duke Operating Entities call the DEC ECC Transmission Operations (TOP) for permission involving a transmission system configuration change involving line switching, transformer and capacitor outages and/or routine and emergent projects.
2) TOP evaluates the request to see what impact changes may have on the system. If there is a negative impact on the system due to increased load or drop in voltage, the TOP may call for an evaluation from Transmission Planning and Voltage and Load Management to study further additional configuration changes or a possible installation of a portable capacitor/s.
3) A parallel call could come to the Transmission Planner for additional evaluation on system effects from the inquiring entity, but usually it is the TOP calling the Transmission Planner for additional evaluation.
    a. Again, this evaluation review is focused on load capacity and % voltage drop on the overall system effecting that system change.
    b. Additional switching or changes within the system configuration
    c. Installation of a portable capacitor used to minimize voltage drops and increase system loading
4) Transmission Planner contacts and discusses system configuration changes with their findings and if further evaluation is needed from a voltage perspective, asks for further detail review from V&L.
5) V&L reviews and sends its results to Transmission Planning and/or the TOP. This could include recommendations for changes in the project schedule or placement location of the portable capacitor/s; if needed.
6) TOP makes the final decision on whether this work goes forward or not to the inquiring entity.
7) If final decision includes the installation of a portable capacitor, then V&L will create a request that is sent to Asset Management for availability and installation. Protection and Controls is also notified for protective settings on 100 kV and above portable capacitors. Protective settings for 44 kV and 66 kV portable capacitors are issued by V&L.

The installation of portable capacitors is necessary at times to maintain acceptable system voltage as a result of equipment failure, maintenance and project activities, and Transmission Planning studies. In order to ensure compliance with NERC Reliability Standards, Voltage and Load staff take on the lead role of the Project Development Team described in Section 3 of the Duke Energy Transmission Cyber Security BES Cyber

System Categorization (NERC CIP-002) procedure (TECP-OPS-TRM-00010). Following this procedure ensures all standard compliance activities are performed.

11. Open Points Assessment

Activities involving changing the status of normally open or normally closed points on the transmission system can impact the BES designation of transmission elements and sites. Activities fitting criteria A) or B) below include an assessment of the impact on the BES designation of any associated equipment and sites 100 kV and up. This assessment will determine whether the related equipment and/or sites will either fit or no longer fit within the definition of BES. The assessment is necessary to identify the impact of the work on relevant NERC Standards that may either need to be considered, or no longer need to be considered for the equipment and/or site.

A) Closing of normally open points between transmission elements 50 kV and up (can create new BES elements/sites), or
B) Opening of normally closed points between transmission elements 50 kV and up (may allow elimination of elements/sites from being considered part of the BES)

These actions can change the applicability of NERC Standards to 100 kV and up elements and/or sites on the transmission system. Definition of BES is maintained by NERC per the linked document.