DUKE POWER TRANSMISSION SYSTEM PLANNING GUIDELINES

System Planning

Power Delivery

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I. SCOPE

This document was designed to provide a summary of the fundamental guidelines used by System Planning employees to plan Duke's 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 System 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 Power 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 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 Planning 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 Pro Forma 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)
- Fall Peak (for current year and next 2 years)
- Spring Valley (for current year and next 3 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. Non-Duke generators with confirmed, firm transmission reservations are modeled as being in-service. 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.

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

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. The generator MW dispatch module within the power flow analysis program applies generator reactive power limits based on the power output levels of each unit. Reactive power output is evaluated to ensure sufficient reactive capacity exists.

C. Power Transactions

Long-term power 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.

Duke participates in several reliability groups that perform transfer studies on a regular basis: VACAR (Virginia-Carolinas Subregion of SERC), VST (VACAR-Southern-TVA-Entergy), VAST (VACAR-AEP-Southern-TVA), VEM (VACAR-ECAR-MAAC).

D. Equipment Ratings

The methodology used to rate transmission facilities encompasses 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
- 12-hour emergency
- 1-hour emergency

E. Nominal Voltages

Nominal voltages on the Duke 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 Duke'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

Duke 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 (VACAR, VST, VAST, VEM, OASIS postings)
- System Impact Studies
- Generation Interconnection and Affected System Studies
- Fault Duty Analyses
- Miscellaneous Losses Evaluation
- Facilities Adequate Evaluations
- Severe Contingency Studies

V. PLANNING GUIDELINES

System 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 (34.5 kV and below) system. Voltages and thermal loadings that violate the following guidelines will result in further analyses. Studies of the bulk transmission system (500 kV and 230 kV) 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.

As a part of the NERC Planning 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, Duke participates in several regional reliability groups: VACAR (Virginia-Carolinas Subregion of SERC), VAST (VACAR-AEP-Southern-TVA), VST (VACAR-Southern-TVA-Entergy), and VEM (VACAR-ECAR-MAAC). 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 Planning Standards and SERC Supplements.

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, Duke conducts its own assessments of the bulk transmission system. While these assessments are typically focused on the Duke system, they cannot be conducted without consideration of neighboring systems.

The effects of a 500 kV or 230 kV event on lower voltage levels must also be considered in conducting analyses of the bulk transmission 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. The guidelines specify minimum and maximum voltage levels, the percent voltage regulation during both normal and contingency conditions, and the percent voltage drop due to contingencies.

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		Maximum Allowable Contingency Voltage Drop
	Minimum	Maximum	
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 Duke'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, how many there are at each station, and the MVA rating.

220/100 kV Autotransformers

Station	Number of 220 kV Autotrfs / Total	Top Nameplate (MVA)
Anderson	1 / 3	224,448,448
Beckerdite	3 / 4	200,200,200,336
Eno	1 / 4	200,200,336,336
Morning Star	2 / 3	150,150,200
N. Greenville	2 / 4	200,224,224,200
Pacolet	1 / 3	200,200,200
Pisgah*	1 / 2	200,200
Tiger	2 / 4	150,150,200,400
Other stations	0 / 68	-
Total	13 / 95**	

*Pisgah AT-2 is on the 95 kV tap.
**Expected in-service transformers for the summer of 2005.

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 transformer 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. The thermal and voltage guidelines should not be violated for either normal operations or under the loss of:

a) A single transmission circuit
b) A single transformer
c) A single generating unit
d) A single reactive power source or sink
e) Combination of a single generating unit and a single transmission circuit, capacitor bank, or transformer
f) Combination of two generating units

Several 230 kV tie stations on the Duke 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 contingencies that should be modeled.

Abnormal Single Contingency Configurations

Tie Station	Outaged facilities for 230 kV line fault	Outaged facilities for 230/100 kV autotransformer fault	Short term Contingency Tests	Long Term Contingency Tests
Bush River	The line and transformer	The transformer and a line	Line & Tx	Tx only
Hodges	The line	The transformer and a line	Line & Tx, Line only	Line & Tx, Tx only
Lakewood	The line	The transformer and a line	Line & Tx, Line only	Line & Tx, Tx only
McDowell	The line and transformer	The transformer and a line	Line & Tx	Line & Tx, Tx only
Morningstar	The line	The transformer and possibly a line *	Line & Tx, Line only	Line & Tx, Tx only
Peacock	The line	The transformer and a line	Line & Tx, Line only	Line & Tx, Tx only
Shady Grove	The line	The transformer and tap line	Tap Line & Tx, Line only	Tap Line & Tx, Tx only
Tuckasegee**	The line	The transformer and a line	Line & Tx	Tx only
Woodlawn	The line and transformer	The transformer and possibly a line *	Line & Tx	Line & Tx, Tx only

*   Depends on which 230/100 kV transformer experiences the fault.
** 230/161 kV transformer

When appropriate, additional analyses will be conducted to review the impact of a combination of single contingencies, considering the probability of occurrence, the appropriate customer outage costs, and the possible system improvements to determine what, if any, remedial actions need to be taken.

D. Miscellaneous

1. Delivery Point Power Factor Standard

Duke has established a power factor standard for all delivery points. This standard is:

- 96.5% lagging power factor or better (equivalent to 98% on the low-side of the transformer) during Duke peak load conditions (leading power factors are acceptable) and
- 100% (Unity) power factor or below during valley load conditions (leading power factors are not acceptable).

The power factor standard is designed to allow full utilization of transmission system equipment, provide support of system voltage levels during peak loading conditions and contingencies, and to help prevent high system voltage levels during valley load conditions.

2. Spare Transformer Policy

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

Spare Transformer Requirements

Type of Transformer	# of Spares
230/100/xx kV Autotransformer	4
30/40/50 MVA 3 phase 100/44 kV	1
20/27/33 MVA 3 phase 100/44 kV	1
12/16/20 MVA 3 phase 100/44 kV	2
6 MVA single phase 100/44 kV	1
4 MVA single phase 100/44 kV	2
3 MVA single phase 100/44 kV	1

3. Transformer Tertiary Study

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

4. Optimal Power Flow (OPF) Studies

OPF studies are conducted to determine the seasonal generator voltage schedules and for reactive power planning. OPF study results are utilized to reduce system losses by adjusting VAR resources and by planning additional resources.

5. Stability

a) Angle

Duke performs stability analyses on large generating units as major generation or transmission changes occur on the system and as required by the Nuclear Regulatory Commission for the nuclear plants. In addition, stability analysis will be performed to comply with NERC Planning Standards. 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 Duke system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC Planning Standards and the SERC Supplements.

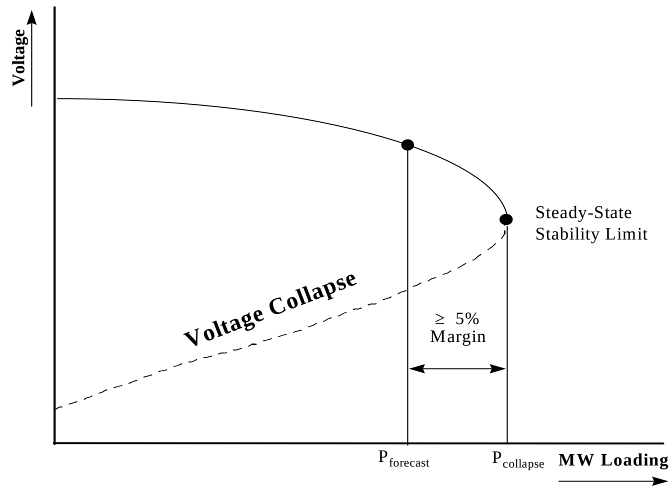
The corrective measures such as faster relaying, transmission upgrades, or unit tripping are determined on an individual basis after considering economics, probability of occurrence, and severity of the disturbance.

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 Planning Standards and the SERC Supplements. To this end, and to ensure the security of the Duke bulk transmission system, the following voltage collapse guideline will be followed:

- For single contingencies of a line or autotransformer and double contingency combinations of lines and/or autotransformers with a generator maintenance outage, the bulk transmission system will be planned to maintain a margin to voltage collapse of greater than or equal to 5% of forecast system load. As shown in the figure below, $P_{collapse}$ must be greater than or equal to 105% of $P_{forecast}$.

Voltage Stability Margin



6. Power Transfer Studies

Power transfer studies may be conducted as a part of a facility addition or upgrade analysis, as a part of a system impact study, as well as with the regional study groups (VACAR, VST, VAST, VEM) to ensure system reliability.

<u>Long-term Planning</u>
An 1100 MW first contingency incremental transfer capability (FCITC) level should be maintained for imports into the Duke system from VACAR to ensure system reliability. Duke has an agreement with four systems within VACAR (CP&L, SCPSA, SCE&G, and VP) to share contingency reserves. By maintaining the 1100 MW level of FCITC with VACAR, Duke has the capability to import the shared reserve requirements from the member systems.

The following first contingency incremental transfer capability levels should be maintained for exports from the Duke system to ensure system reliability:

Non-Simultaneous Export Capability

Importing System	Minimum FCITC (MW)
CP&L	600
SCPSA	600
SCE&G	600
VP	600

Duke maintains adequate export capability with the four VACAR systems that share operating reserves to deliver Duke's portion of the reserve.

Available Transmission Capability ("ATC") is the measure of the transfer capability remaining in the physical transmission network for further transmission service over and above committed use. At the present time, the guidance for calculating and coordinating ATC is changing and becoming better defined. Duke is an active participant in industry organizations developing the methodologies and intends to apply applicable NERC, SERC and other industry guidance for calculating ATC.

7. 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.

8. Fault Duty

Fault duty studies are performed to indicate the available fault duty for each transmission system (500, 230, 161, 100, 66, and 44 kV) breaker location. These fault duty study results are used to verify acceptable fault capability of breakers already in service. The results are also used to assist in the selection of new breakers to be installed. As system changes or additions are made, a fault duty study is done as needed for both current and future system configurations.

<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
- two 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
- maximum operating voltage

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 not explicitly modeled are calculated using fault duty at the associated network bus and the impedance of the radial elements.

9. 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.

10. Facilities Adequate Evaluations

Facility evaluations are performed when a customer requests a change in contract MW. The existing equipment, metering and analysis are evaluated for the proposed increase in load and a determination is made concerning any necessary improvements.

11. Severe Contingency Studies

NERC Planning Standards instruct transmission providers to evaluate extreme (highly improbable) contingency events resulting in multiple elements removed or cascading out of service. The SERC Supplement outlines SERC's expectations of members with regard to the NERC Standards. All severe contingency simulations are analyzed and verify that cascading off system does not occur.

The following contingencies are modeled to ensure compliance with the standards to avoid cascading outages:

a) Loss of all circuits on a common structure
b) Loss of all circuits on a common right-of-way
c) Loss of any single network 500 kV, 230 kV, 161 kV or interconnection bus
d) Loss of a complete voltage level at a station
e) Loss of all generation at a station
f) Outage of a critical transmission line caused by a three-phase fault during the outage of another critical transmission line.
g) Delayed clearing of a three-phase fault on the system due to failure of a breaker to open.