Guidelines for Planning
The Southern Company Electric
Transmission System

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I. Scope

The guidelines contained in this document shall be used as the basis for the planning of transmission facilities within the Southern electric system. Implementing these guidelines will require close coordination throughout the planning process, including project initiation, budgeting and prioritization. Transmission system assessments involving regional and sub-regional concerns and interface requirements with neighboring systems will be addressed in other forums including NERC, SERC, VST, Southern/FRCC, etc.

II. Transmission Planning Objectives

The objectives that shall remain foremost in the planning of transmission facilities for the Southern electric system are as follows:

a. To normally serve all territorial loads.
b. To provide for the effective use of all generating resources with Firm Transmission Service.
c. To provide for output of any generating plant up to it's Firm Transmission Service.
d. To satisfy firm contractual transmission service obligations.
e. To provide a level of margin that will protect against the more probable and severe contingencies that might be anticipated on the system within the planning horizon.
f. To allow outage for maintenance of any element in the bulk power system during normal maintenance periods.
g. To provide for the normal operation of system protective devices, including bus differential schemes, due to a single event, without resulting in uncontrolled cascading outages and/or widespread loss of load.
h. To use existing resources (i.e., rights of way, voltage conversions, double circuit lines, etc.) when feasible to reduce costs.
i. To minimize transmission losses when cost effective.
j. To optimally balance risks and expenditures in order to ensure an economic and reliable system.

The planning of transmission facilities will recognize the acceptance of appropriate levels of risk such that the system will not always be able to meet the above stated objectives. Therefore, recommendations for transmission facility improvements to support these objectives will be addressed only after risk assessment has been performed.

III. Performance Guidelines

The evaluation of power flows, transient voltages and steady state voltages are the normal means by which the system planner shall determine satisfactory performance of the transmission system. System voltages and power flows must not only be evaluated for normal conditions but also for post-contingency conditions. System conditions falling within the following performance guidelines will be deemed satisfactory unless tighter guidelines have been identified to accommodate special requirements, including but not limited to, governmental regulations, highly voltage-sensitive customer operations or machine stability limitations.

A. Voltage Security

- Generator Bus Voltage Levels
  The voltage at the generator terminal busses should not exceed the maximum or fall below the minimum allowable voltage limits for all facilities in-service and planning contingency conditions. It is expected that the generator owner will specify equipment such that the voltage limit range for a generator lowside bus is 0.95 – 1.05 pu. However, as determined on a case by case basis, reduced ranges may be acceptable. For additional details regarding the Voltage Security guidelines, refer to "Southern Company Reactive Guidelines" document. Acceptable transmission bus voltage ranges are listed in Table 1 below.
- Transmission Voltage levels

Table 1. Acceptable Transmission Voltage Level Ranges in per unit of nominal voltage

		500 kV	230 kV	161 kV	115 kV (See Note 1)
No Contingency	High-side of Generator GSU Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Switching Station	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Regulated Load Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Non-regulated Load Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
Planning Contingency in Effect	High-side of Generator GSU Bus	0.98 – 1.075 and generator should maintain voltage schedule	0.95 – 1.05 and generator should maintain voltage schedule	0.95 – 1.05 and generator should maintain voltage schedule	0.95 – 1.05 and generator should maintain voltage schedule
	Switching Station	0.97 – 1.075	0.9 – 1.05	0.9 – 1.05	0.9 – 1.05
	Regulated Load Bus	0.97 – 1.075, and not to exceed 0.08 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.08 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.08 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.08 p.u. deviation from pre-contingency voltage
	Non-regulated Load Bus	0.97 – 1.075, and not to exceed 0.05 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.05 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.05 p.u. deviation from pre-contingency voltage	0.9 – 1.05, and not to exceed 0.05 p.u. deviation from pre-contingency voltage

Notes:

1)Equipment Ratings and/or Transformer Tap Settings may result in tighter ranges at some buses. This includes but is not limited to voltages at buses

with 110 kV rated equipment which typically would result in a reduced high voltage level limit from 1.05 to 1.04.

2) For the purpose of voltage level criteria, the generator transmission high-side bus should be treated like a non-regulated load serving bus for the following conditions:
   a) If no units at a plant are turned on in normal (no planning contingency in effect) power-flow evaluation
   b) If for single unit plants, for a normal planning contingency that involves the outage of the same aforementioned unit
   c) If a plant has been deemed exempt from the NERC Planning Standards requirement of having to hold a voltage schedule
   d) For low MVA plants (<100 MVA) where a plant is defined as one or more units that are on-line in the power-flow and are interconnected to the same transmission bus.
3) Exceptions could be considered for plants above 100 MVA that cannot hold voltage schedule for some standard planning contingencies, if
   a) Voltage stability margins are above the minimum 5% threshold and
   b) Power-flow analysis indicates that there are no other voltage violations at any load serving buses

- Minimal Voltage Security Real Power Margins

  A voltage security margin of 5% or greater should be demonstrated for the load area modeled. To demonstrate this margin, the power-flow case has to be voltage secure for a 5% increase in MW load over the initial MW load in the area under study with planning contingencies applied.

  A voltage security margin of 5% or greater should be demonstrated for any transfer path (interface or defined flow gate). To demonstrate this margin, the power-flow case has to be voltage secure for a 5% increase in the MW transfer over the base transfer path rating for the transfer path under study with planning contingencies applied.

B. Transmission Thermal Loading

All new transmission lines will be rated commensurate with Southern Company line rating methodology.

- <u>Transmission Lines</u>

  Transmission line loading should not exceed levels which result in violating design specifications of the terminal connections, substation infrastructure or of the line itself. The limiting element of each transmission line shall be the circuit element with the lowest ampere (thermal) rating. Ampere ratings afforded by these design limitations should be dictated by the ambient assumptions appropriate for the seasonal (load) conditions being evaluated. In the load flow model, the “B” rating of the transmission line model shall be used to evaluate the loading of each transmission facility except when performing special studies or hot weather studies.
- <u>Transmission Transformers</u>

  Transmission transformer loading should rely on the nameplate data or the Large Power Transformer Loading Guide evaluation as a source of information to establish the rating.

IV. Risk Assessment

To facilitate the risk assessment in the planning process, the following factors should be considered: (1) duration, (2) exposure, (3) severity, (4) consequences (e.g. expected

unserved energy) and (5) required operator action.

A. Duration
It is recognized that a time period is required to accommodate the following actions: Line switching, capacitor switching, unit start-up, etc., all of which need to be considered in restoring conditions to acceptable system performance. A transmission facility should not be allowed to exceed its normal design rating nor should a transmission bus be operated below its low voltage limit for more than the time required to accommodate automatic, supervisory, and/or manual switching of available system equipment.

B. Exposure
The probability of a particular contingency or group of contingencies, which causes a violation of the transmission performance guidelines, should be considered when evaluating the exposure to risks.

C. Severity
The severity of a problem caused by a contingency or a number of contingencies is gauged by the resultant level of overload and/or voltage. Most transmission facilities can be loaded above normal design ratings or incur under/over voltage conditions for short periods of time. However, it is not acceptable for any transmission facility to be loaded above maximum levels or be subjected to voltages that will violate design/code standards.

D. Consequences
Key issues to be considered in assessing consequences are: (1) number of customers impacted; (2) amount of load dropped; (3) bulk and area network impacts; (4) cascading effects; etc. Most of these issues must be addressed on a case-by-case basis. However, load shedding and customer impacts should not exceed levels identified by the DOE and as defined in FPC Order No. 331-1 (Docket No. R-361).

E. Required Operator Action
The use of operating procedures is, in many cases, a viable alternative to making system improvements. In considering the use of an operating procedure, operator action time as well as procedure complexity must be assessed when considering the overall effectiveness to correct the specific problem. If, for any reason, the use of an operating procedure results in a violation of the aforementioned risk assessment factors, then the operating procedure should be avoided.

V. Basecase Development

Transmission base cases are developed or modified at least on an annual basis to reflect the most current information and assumptions available concerning the modeling of future year's system load distribution and growth, generation and transmission expansion, firm transmission service obligations and representations of similar assumptions for other systems. The assumptions used in the base case development are a starting point for evaluating the adequacy of the transmission system to meet firm transmission service requirements and system reliability. Other load, generation, etc. assumptions may be evaluated as sensitivities.

Generation participation is based upon the latest information available concerning transmission service agreements, network resource designations, and native load reservations made by network customers to meet future load growth. Loads are generally based on the latest load forecast from all network loads for peak conditions. Other loading conditions, reflecting different time periods or temperature conditions are also developed and evaluated. All transmission and substation components are rated based on appropriate and industry recognized IEEE, ANSI or NESC standards and Southern

Company design practices. External system representations are based on MMWG or VST data bank models.

VI. Planning Assumptions

A. General Assumptions

- The guidelines identified in this document apply to the transmission facilities necessary to transport power at the 110 kV level and above.
- Study case loads are generally based on the latest forecast from all network load customers for peak conditions and reflect the loads for which transmission service must be provided. Other loading conditions, reflecting different time periods or temperature conditions are also developed and evaluated.
- The current year best estimate of generation expansion by all network transmission users and generators with approved Transmission Service Agreements will be used for generating resources, and system generation dispatch will appropriately consider contractual transmission service obligations, unit commitment, area protection, hydro availability, and economic dispatch, consistent with the load level being evaluated. Other generation scenarios may be evaluated as sensitivities.
- Interchange shall be that which is contracted at the time of the planning studies. Economy interchange dispatch shall be zero or tested as a sensitivity. Other reservations, such as CBM, TRM, native load reservations may also be tested.
- Transient and dynamics effects should be considered where appropriate and should be consistent with the objectives of Section IV and the guidelines referenced in Section VII.C.
- These planning guidelines will be used, along with regional planning guidelines to provide an economic and reliable transmission expansion plan for the Southern electric system.

B. Operating Procedures

Proposed operating procedures should be simple and have the ability to be quickly performed to prevent thermal or voltage violations and should be validated yearly with the Control Center that has operational control over the facilities impacted. In general, operating procedures that require the switching of equipment operated at voltages higher than 161kV will not be utilized. In general, operating procedures should not be considered as a long term solution to a system problem.

C. Generation Participation

Transmission base cases are developed with assumptions of generation dispatch and generator unit run requirements for area protection. Studies use these assumptions as a starting point for evaluation. Other generation conditions may be tested as a sensitivity.

D. Reactive Requirements for Generation

The “Reactive Policy for Generation Facilities Connecting to the Southern Company Transmission System” outlines the amount of reactive power capabilities required from generating facilities connected to the Southern Company transmission system.

VII. Planning Contingencies

The transmission system should be tested against the following planning contingencies as appropriate, to ensure that the network transmission system is being planned to meet the objectives identified in Section II;

A. System Adequacy

- At 100% Peak Load Level
  - Loss of any one (1) critical generating unit and any one (1) transmission element or
  - Loss of any two (2) generating units.
  - Use Rate "B" thermal violation limits.
- At 93% of Peak Load Level (Shoulder - Hydro off or motoring)
  - Loss of any one (1) transmission element.
  - Consideration may be given to the loss of a generating unit in combination with the above contingencies.
  - Use Rate "B" thermal violation limits.
- Special studies.
  - Multiple unit and voltage levels at plants.
  - Breaker Failure/Bus Differential Scenarios.
  - Loss of Common Tower structures or ROW outages.
  - Stability studies etc.
  - Low probability, high consequence system reliability studies.
  - At all load levels, generation scenarios may be evaluated for increasing generation in a given area, up to the maximum generating capacity of that area.
  - At 105% of Peak Load Level (Reduced dispatch of hydro generation) Studies may be conducted to evaluate the impact of loss of any one (1) generating unit or one (1) transmission element. Such studies should use Rate "A" as the thermal violation limit.
  - At load levels below 93% of Peak Load Level
    Studies may be conducted to evaluate the impact of not more than one transmission element and/or one generating unit outage in conjunction with various transmission and generation maintenance outage scenarios.

B. Reliability

Additional studies should be conducted to assess levels of reliability and the risks resulting from contingencies on the transmission system. These studies utilize specialized methods and data, including transmission line and generator outage data. Contingencies evaluated include those outlined in Section VII.A above, plus other contingency types intended to meet NERC standards for low probability high consequence events. In addition to meeting NERC requirements, the reliability studies allow the assessment of both system reliability performance, using measures such as SAIDI and SAIFI, and physical infrastructure security. These studies are specialized and distinct from other reliability studies such as those found in Section IX.

C. Stability Studies

Reference:
Attachment A: "Stability Criteria and Guidelines"
Attachment B: "Assumptions for Stability Studies"

VIII. Budget and Forecast Studies

Budget and forecast studies are performed each year to assess the timing of budgeted projects and to investigate the need for additional projects within the current budget time frame. These studies provide the basis for the Transmission Expansion Plan. Long Range scenario studies are performed for the outer years in the planning horizon to identify the potential scope of future transmission expansion plans.

IX. Transmission Interface Studies

Studies of the transmission interfaces are conducted on a regular basis to ensure adequate capability to meet all firm transmission obligations, maintain system reliability and meet intercompany reliability agreement requirements. Studies are conducted utilizing NERC, regional, sub-regional practices, guidelines, definitions, reference documents, and other related information. Studies are also conducted to identify the transfer capability required by FERC for posting on OASIS.

X. Generation Studies

For Transmission Service Requests and Generator Interconnection studies, Southern Operating Companies currently study and offer transmission service based upon their Open Access Transmission Tariff filed with the Federal Energy Regulatory Commission. A copy of the document can be found at http://www.weboasis.com/OASIS/SOCO/INFO.HTM. Study methodologies generally adhere to the preceding sections of this document subsequent to the requirements of the OATT and commission orders.

X. Operating Studies

The use of operating procedures to mitigate thermal or voltage problems on the transmission will be investigated and validated each year. New operating procedures must be validated by the regional control center (ACC for APC, GCC for GPC, etc…). Special operating studies include:

- Support for outage scheduling and construction schedules.
- Special contingency analysis and decision making support
- System analysis for lengthy unscheduled outages
- System analysis for extended periods of inclement weather.

XI. Nuclear Assessment Analysis

Transmission and generation changes that may impact nuclear plant operating conditions should be evaluated to determine the impact both on plant stability and critical substation voltages. Each nuclear plant has a specific Final Safety Analysis Report (FSAR) which delineates the design and operational requirements of each plant, including characteristics of off-site power quality. Specific details regarding plant loading, conditions to be evaluated, system contingencies, and other criteria are identified in the Power Quality Guide specific to each plant. Any changes to the system that may impact these requirements must be evaluated and coordinated with System Operations and Southern Nuclear.