AMERICAN ELECTRIC POWER – 2010 FILING

FERC FORM 715 – ANNUAL TRANSMISSION PLANNING AND EVALUATION REPORT

PART 4 – TRANSMISSION PLANNING RELIABILITY CRITERIA AEP-Texas

TCC, TNC and ETT are all members of the Electric Reliability Council of Texas (ERCOT), and as a condition of membership have agreed to conform to all approved and applicable ERCOT and North American Electric Reliability Corporation (NERC) Reliability Standards (NERC Standards) for the Bulk Electric Systems of North America. The ERCOT Reliability Criteria (ERCOT Operating Guides Section 5: Planning) is made available by ERCOT without conditions to FERC and the public for download from Internet Web Page: http://www.ercot.com/mktrules/guides/operating/current.html.

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Common transmission reliability criteria for TCC, TNC and ETT have been developed and are included in this report. TCC, TNC and ETT comply with the ERCOT Reliability Criteria, the NERC Standards and the American Electric Power Transmission Reliability Criteria as the basis for the planning and design of the TCC, TNC and ETT transmission systems.

American Electric Power

Transmission Planning Reliability Criteria

TCC, TNC and ETT transmission lines and substations, which operate at voltages of 69 kV and above, are used to transfer power from generating stations to load centers or to interconnect with other electric utilities for the purpose of providing reliable electric supply to load serving entities and making power transfers. AEPSC is the operator of TCC, TNC and ETT and uses Good Utility Practice to ensure its transmission system is in compliance with the ERCOT Reliability Criteria and NERC Standards as applicable, as well as the specific criteria listed below.

1. Nominal Voltage Levels
   Nominal 345 kV and 138 kV voltage levels will normally be used for most new power transmission lines. Some interconnection lines may be at 115 kV, 230 kV, or 500 kV to match neighboring utilities' voltage, and some 69 kV lines may be constructed in appropriate situations.

2. Voltage Regulation
   (a) Generators are generally scheduled to hold higher than nominal generator voltage during peak load periods to stabilize transmission system voltages.
   (b) Capacitor banks, reactors, and LTC auto-transformers are used in transmission substations to hold voltage levels within acceptable ranges during normal and emergency conditions.
   (c) System conditions must be controlled so as to prevent excessive LTC tap changes.
   (d) Dynamic reactive resources, static var systems, stored energy devices, and series compensation are used as appropriate.

3. Voltage Limits
   (a) Transmission voltages should not exceed 105% nor fall below 95% of the nominal voltages shown above during normal operation of the system.
   (b) Transmission voltages during emergencies should not exceed equipment overexcitation ratings.
   (c) Transmission voltages during emergencies should not result in customer voltages exceeding or falling below prescribed limits at distribution substations on the transmission system.
   (d) Transmission voltage should not exceed 105% nor fall below 90% of nominal voltage shown above during emergencies. The low limit can be lower if voltage regulating equipment maintains voltage to the customers within prescribed limits at distribution substations involved without causing voltage problems at nearby loads.
   e) The random voltage fluctuations (flicker) occurring at the Compliance Point directly attributable to the Customer shall remain within the limits specified in IEEE Standard 1453-2004, "IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light

Flicker on AC Power Systems." These limits are 0.8 and 0.6 for the PST (short term) and PLT (long term) flicker measures, respectively. PST is the standard reading of a flicker meter, obtained for each 10-minute interval; PLT is derived mathematically (cube root-mean-cube) from twelve consecutive PST readings (see Appendix A, Exhibit 1).

4. Thermal Capabilities of Transmission Facilities

Thermal Limits - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission equipment ratings are documented by AEP standards and guides.

5. Reactive Power Capability

Reactive power resources will be provided in amounts that are sufficient for system voltage control under normal and contingency conditions, including the dynamic period following system disturbances. Each AEP operating company and ETT is responsible for providing or arranging for the provision of reactive power reasonably adequate to supply both its own reactive power load and any reactive power losses associated with service to its transmission service load, whether such losses are incurred on its own system or the facilities of others. Transmission Planning with System Operations will coordinate reactive power resource planning.

The power factor for each operating company and its major sub-areas will be maintained as follows:

(a) The overall system power factor range should be maintained at 99-100% lagging. This will be calculated from the net MW and MVAr flows on the high side of the generator step-up transformers, and at the interconnections. A net power factor of 97%-100% lagging should be maintained on the generator side of the step-up transformer.

(b) Leading power factor on generators will normally be used only for off-peak, low load situations for limited amounts of time, to reduce the likelihood of generator instability.

6. Transmission Capacity and Load at Risk

(a) Transmission capacity of individual power transmission lines is planned so generation can be economically scheduled for all load levels with all lines in service with consideration of the cost of transmission losses and future loading of the lines.
(b) With one line or transformer out of service, no generation or load curtailment should be necessary.
(c) The minimum transmission capacity to a major transmission substation will be maintained at the substation rating with the largest incoming line out of service.

7. Stability

Stability testing covers the entire range of power system dynamics from "first swing" transient stability to longer term oscillatory and steady-state stability. This testing is an essential complement to the steady-state analysis embodied in load flow testing.

Maintaining power plant transient stability is essential because loss of synchronism (or instability) of a generating unit or an entire generating plant can lead to equipment damage and severe power system transient swings. Instability may further compound a disturbance by causing the tripping of the unstable generators and possibly other equipment. When simulating system contingencies affecting power plant stability, various types of fault and network conditions are analyzed in accordance with the transient stability disturbance testing criteria outlined in Appendix B. The generator's responsibility for facility upgrades as identified in the table is dependent on the regulatory provisions in the jurisdiction in which the generator is interconnected.

The transient stability disturbance testing criteria in Appendix B specifies the disturbance events for which stable operation is required of all transmission and EHV connected generation. The stability testing criteria appropriate for sub-transmission and distribution connected generation is determined on a case-by-case basis and may be less stringent as long as instability may be shown not to adversely affect the bulk transmission system. In cases where the bulk power system is not adversely affected and the speed of sub-transmission or distribution system protection is inadequate to prevent instability for normally cleared faults, out-of-step tripping would be required to prevent adverse effects on the sub-transmission or distribution systems.

Steady-state and oscillatory stability performance problems may be initiated by a wide variety of contingencies or operating conditions on the transmission network. Appendix B network disturbances are similarly applied when testing for steady-state and oscillatory instability and these criteria are sufficient for detecting these types of instability.

AEPSC generally carries out simulations corresponding to the A through E set of criteria in Appendix B for facility planning studies. For operational planning studies, the F and G criteria, in addition to the A-E set, are applied, especially when a long-term facility outage is anticipated. Testing of more severe disturbances than those in the table may be performed to evaluate the strength of the transmission system and to assess potential for cascading outages. Examples of such testing include common-failure mode disturbances such as double circuit tower faults or bus faults that result in the outage of multiple facilities at a location.

The disconnection of generation due to a disturbance is distinct from instability. Instability refers to loss of synchronism or pole slipping when the generation remains physically connected. Disconnection results in generator overspeed followed by turbine shutdown in response to protective relay action. Systems are planned such that disconnection does not occur for single contingencies. Disconnection may occur during disturbance scenarios involving the outage of more than one transmission element, or common-failure mode disturbances such as bus outages, as a consequence of isolating faulted facilities or other system design considerations. Disconnection under these circumstances is considered to be acceptable whereas instability is not.

8. Reliability

(a) More probable contingency testing shall investigate the following situations:
   (1) Loss of any single critical transmission line,
   (2) Loss of any single transformer,
   (3) Loss of any bus section,
   (4) Loss of any double circuit line of one mile or greater length,
   (5) Loss of any tie breaker,
   (6) Loss of any generating unit,
   (7) Loss of a critical transmission line or auto-transformer when any generating unit is unavailable, and

(b) For the occurrence of any of the above more probable contingencies, testing must conclude that:
   (1) All facility loadings are within their emergency ratings and all voltages are within their emergency limits, and
   (2) Facility loadings can be returned to their normal limits within two hours.

(c) Less probable contingency testing shall investigate the following situations:
   (1) Loss of any combination of related facilities, a critical transmission line when a 345 kV auto-transformer is out of service, or a generating unit when another generating unit is out of service.
   (2) Sudden outage of any multi-circuit transmission line at a time when any other single circuit is out of service,
   (3) Sudden outage of any single or double-circuit transmission tower line at a time when two generating units are out of service, for maintenance or economics,
   (4) Sudden outage of any generating unit at a time when any two other generating units are out of service for maintenance or economics,

(d) For the occurrence of any of the above less probable contingencies, testing must conclude that neither uncontrolled islanding, nor uncontrolled loss of large amounts of load will result.

VOLTAGE FLICKER REQUIREMENTS

[Based on IEEE Standard 1453-2004, "IEEE Recommended Practice for Measurement And Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems"]

Voltage Flicker Measure	Maximum Value
P_{ST} (Short Term)	0.8
P_{LT} (Long Term)	0.6

AEP TRANSIENT STABILITY DISTURBANCE TESTING CRITERIA

PREFAULT CONDITION	765 KV PLANTS	345 KV PLANTS	138 KV PLANTS
All Transmission Facilities in Service	1A Permanent single line-to-ground (SLG) fault with 1φ breaker failure. Fault cleared by backup breakers.	2A Permanent SLG fault with 1φ breaker failure. Fault cleared by backup breakers.	3A Permanent SLG fault with 3φ breaker failure. Fault cleared by backup breakers.
	1B Permanent SLG fault cleared by primary breakers. 3φ fault developed following HSR. Fault cleared by primary breakers.	2B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3B Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1C 3φ line opening without fault.	2C 3φ line opening without fault.	3C 3φ line opening without fault.
One Transmission Facility Out of Service	1D Permanent SLG fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	2D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.	3D Permanent 3φ fault with unsuccessful HSR, if applicable. Fault cleared by primary breakers.
	1E 3φ line opening without fault.	2E 3φ line opening without fault.	3E 3φ line opening without fault.
Two Transmission Facilities Out of Service	1F Temporary SLG fault with successful HSR, if applicable.	2F Temporary 3φ fault with successful HSR, if applicable.	3F Temporary 3φ fault with successful HSR, if applicable.
	1G 3φ line opening without fault.	2G 3φ line opening without fault.	3G 3φ line opening without fault.