

**AMERICAN ELECTRIC POWER – 2009 FILING**

**FERC FORM 715 – ANNUAL TRANSMISSION PLANNING  
AND EVALUATION REPORT**

**PART 4 – TRANSMISSION PLANNING RELIABILITY CRITERIA  
EASTERN AEP**

Attached is a document entitled "The American Electric Power System Transmission Planning Criteria and Assessment Practices Eastern AEP". This document provides the criteria to test and assess the strength of AEP's transmission system to meet its load responsibility, including power transfers with other systems (including activity within PJM) as well as to move bulk power between and among other electric systems. This document, in conjunction with the documents submitted under Part 5, provides a description of transmission planning criteria and assessment practices for the AEP System.

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**THE AMERICAN ELECTRIC POWER SYSTEM**

**TRANSMISSION PLANNING CRITERIA  
AND ASSESSMENT PRACTICES**

**EASTERN AEP**

East Transmission Planning  
Transmission Asset Management

American Electric Power Service Corporation

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## **Introduction**

Electric utilities, such as AEP, meet their obligation to supply electricity demanded by their customers with a high degree of reliability through the carefully planned development of electric generating sources, transmission, and distribution systems. The reliable supply of electricity involves two elements – adequacy and security. "Adequacy" relates to the production and delivery of electric power and energy in the quantity and quality that the customer requires. For example, sufficient power must be provided at acceptable voltage levels and frequency to match the customers' equipment specifications. "Security" relates to the ability to produce and deliver power whenever the customer needs it. Credible contingencies, such as the sudden outage of transmission facilities, should not result in uncontrollable power interruptions over a wide area. Planning a reliable transmission system requires the application of fundamental principles and the establishment of criteria, which balance adequacy and security against the cost to provide them.

The eastern AEP transmission system was developed over many decades. In the early days of the utility industry, power plants were small and located near load centers. Consequently, transmission distances between the generation resources and the ultimate consumer were comparatively short and the amounts of power delivered were small. As the demand for electricity increased, larger power plants were designed and built further from the load centers to exploit economies of scale, and greater amounts of power had to be transmitted over longer distances. This led to the development of higher voltage, higher capacity transmission facilities.

As utilities developed in their respective geographic areas, the establishment of interconnecting transmission facilities between adjacent systems became attractive as a means to provide mutual support during emergencies and to avoid constructing duplicate facilities. The high transmission voltages have enabled power systems to interconnect on a broad scale. Interconnections allow utilities to support each other during forced or scheduled generation and transmission outages, to buy and sell power for reasons of economy and thereby enhance reliable and economic operation. On the other hand, each interconnected system is unavoidably impacted by events on neighboring systems, requiring coordinated planning and operating practices among neighboring systems and regions. Facility outages and variations in generation dispatch within one system will affect power flow patterns in neighboring systems. Consequently, cascading outages that affect widespread areas are possible. The highly interconnected nature of electric utilities has made it necessary that system planning criteria evolve to recognize these interrelated consequences of interconnected operation.

This document describes the criteria that AEP uses for planning a reliable transmission system to meet its customers' needs at the lowest cost. The first section describes the principles underlying the planning criteria and discusses the planning process. The following three sections provide details of modeling assumptions, performance expectations, and testing criteria, respectively, for AEP's bulk transmission system and area transmission system.

AEP's eastern bulk transmission system, which consists of an extensive network of extra high voltage (EHV) facilities generally operating at 345 kV and above, delivers power from generating plants to major load centers, connects load centers together to form an integrated network, and connects the AEP System to neighboring companies. The area transmission system, which consists

of high voltage (HV) facilities operating at 230 kV, 161 kV, 138 kV and 115 kV and lower voltage subtransmission facilities (from 23 kV to 88 kV), moves power within the major load centers and delivers it to distribution centers and major customers. Even though AEP's eastern bulk and area transmission systems are planned and operated on a totally integrated basis, the planning criteria of each differ because of separate and distinct functions that each of these systems are intended to serve.

# **1. UNDERLYING PRINCIPLES AND THE PLANNING PROCESS**

## **1.1 Underlying Principles**

Although planning is essential in any industry, it is critical for electric utilities due to the characteristics of an electric power system: the inherent need to respond instantaneously to the electric power demand of customers (load); the heavy financial investment and long service lives of its facilities; the long lead and construction times to add facilities; and the social and economic importance of a reliable power supply. AEP has adopted fundamental planning principles as the basis for specific reliability criteria. Briefly, these principles state that a properly designed transmission system should provide a good distribution of power flows by avoiding excessive geographic concentrations of generating sources or transmission paths. A transmission system should have ample margin to allow for contingencies so as to avoid uncontrolled, area-wide power interruptions and also provide flexibility to deal with the uncertainties inherent in making long range forecasts. Interconnection capabilities between systems should be maintained commensurate with the amount of system load and the size of the individual generating units connected to the transmission system. Station switching arrangements, relay protection, and system controls should be adequate to maximize the use of the transmission system and minimize interruptions; and to provide flexibility for scheduling required maintenance as well as facilitating the restoration of outaged facilities while always, and most importantly, insuring the safety of the general public and our employees.

It is impossible to anticipate or test all possible contingencies that could adversely affect the eastern AEP transmission system because of the large number of individual elements that comprise the system and the fact that power flows, and load levels are continually changing. Therefore, the planning criteria and related contingency tests outlined in this report do not represent an exhaustive set of system operating conditions, transfer levels, and specific contingencies; instead, they constitute an effective and practical means to stress the eastern AEP transmission system, testing its ability to survive the entire spectrum of possible contingencies and identifying potential weaknesses and problems.

The AEP criteria described herein are compatible with: 1) the North American Electric Reliability Council (NERC) Reliability Standards; 2) the Reliability *First* Corporation (RFC) Standards, and 3) other external documents. A listing of those external documents is provided in Appendix A. The application of the NERC and RFC criteria to any particular utility system, including AEP, must be adapted to the specific characteristics of that utility. Each utility's transmission system is configured in a way that is specific to the geographic region it serves as well as the electrical facilities that are installed to meet these requirements. There are also various ways of achieving reliability objectives. Therefore, differences can exist among the specific planning criteria employed by various systems. Compatibility among different systems' criteria and guidelines are achieved, however, by adopting fundamentally sound planning principles and practices.

This report presents an overview of AEP's eastern transmission planning criteria and assessment practices. Specific application of these criteria and practices on a case-by-case basis must employ sound engineering judgment. The transmission planner conducting each study should always

evaluate these criteria and apply them in such a manner to account for special considerations applicable to the area under study (commonly referred to as sensitivity analysis).

Due to inherent uncertainties associated with forecasts of loads, new technological developments, equipment costs, and changing social, economic, and political conditions, it is prudent to develop long range plans of transmission system expansion/modification based on a range of assumed scenarios. Sensitivity analysis is also useful in making these judgments. By their very nature, long-range plans must be reevaluated and modified periodically to reflect the persistent changes in the variety of factors that influence future system performance. While current planning criteria are inherently deterministic, qualitative distinctions about the likelihood of various scenarios and contingencies are recognized.

More likely events require higher levels of system performance; lower system performance standards (greater negative impacts) are acceptable for events that are less likely to happen. Deterministic reliability criteria that are sufficiently stringent to ferret out potential system problems may also result in specific design consequences, which are impractical or too expensive in relation to the benefits realized or the risks mitigated. In these cases, prudent exceptions to the criteria can be made, or other less expensive control schemes employed.

## **1.2 Planning Process**

The planning process, as carried out in the eastern AEP area, provides the focus for establishing an appropriate level of system reliability. The planning process includes seasonal assessments of system performance; near term facility addition studies; and long term strategic planning. The planning process typically begins with a deterministic appraisal of transmission system performance. When such appraisals identify potential problems, detailed studies are conducted to evaluate the severity of the problem and to develop an optimal plan to remove or mitigate the deficiency.

Seasonal assessments, also referred to as operational planning, have a horizon of up to one year. These appraisals verify that the transmission system, as planned and built based on long term predictions and assumptions, is adequate to meet the actual requirements that emerge for the approaching peak load periods. Delays in transmission reinforcements, and changing power flow patterns or performance expectations, also influence the need for short-term appraisals. These appraisals also provide an early warning of future system reinforcement needs. Operational planning appraisals are conducted in a manner similar to facility planning appraisals. The major difference is that problems identified in these assessments typically cannot be corrected by transmission reinforcements due to insufficient lead time. Therefore, problems identified by these studies are addressed by deriving indices for system operators to monitor system performance and establishing operating procedures to mitigate any transmission problems detected by the operators during real time operation.

Near term (1 to 5 years) and long term (more than 5 years) facility planning appraisals analyze anticipated system conditions within the specified time period. Near term and long term planning of the transmission system allows adequate time to identify emerging trends and anticipated system

deficiencies and then to plan and build needed transmission reinforcements, including time for potentially lengthy regulatory approval processes.

Near and long term facility planning and operational planning studies are conducted for both the bulk transmission system and the area transmission system in accordance with their respective testing criteria and performance expectations. The majority of these studies are conducted internally by AEP transmission planners supplemented by information generally available from neighboring electric utilities. In addition, joint planning studies involving one or more neighboring systems and/or the appropriate Regional Transmission Organization(s) are carried out to assess and enhance the transmission interfaces between AEP and its neighbors through the coordination of operating procedures, development of new interconnection facilities and/or coordinated transmission enhancements within each system.

AEP's eastern Transmission Planning Organization continues to receive requests through PJM from merchant plant developers for interconnection of new generators to the eastern AEP transmission system. PJM assesses the impact of these generation projects on the AEP's bulk transmission system. The PJM studies are supplemented by studies conducted by AEP transmission planners. The integration of new generation into the AEP transmission system is conducted based on the same planning principles as for any other transmission facilities.

In addition, seasonal, near term and long term appraisal studies, limited to assessing regional and inter-regional transmission system performance, are conducted jointly with neighboring utilities as part of PJM, RFC and Eastern Interconnection Reliability Assessment Group (ERAG) agreements. These joint appraisals focus on measuring the strength of the interconnected network and on assuring coordination of facility planning and operational planning efforts. Where such assessments uncover deficiencies, the specific findings are referred to the appropriate company or companies to develop solutions as part of their normal planning process.

This document does not directly address regional and interregional appraisal criteria except to note that AEP's criteria comply with those in RFC and NERC Reliability Standards. Also, AEP uses regional and interregional transfer capability measures that are consistent with the NERC definitions, to assess the strength of its transmission system. AEP is an active participant in many regional and interregional study groups and has made significant contributions to the development of regional and interregional criteria, including RFC and NERC Reliability Standards.

## **2. KEY MODELING ASSUMPTIONS**

The computer models used in transmission planning studies necessarily differ widely in dimensions and details to suit the scope of each study. Power flow models are developed to represent system operation during highly stressed periods such as peak load conditions and heavy power transfers that simulate emergency and opportunity power transactions. System dynamics and short circuit computer models are also used, depending on the specific analysis, to complement the power flow models. Using these computer models, transmission system performance is assessed by simulating disturbances to identify system strengths and weaknesses. In general, the following assumptions are used in conducting various types of transmission planning studies.

System active power (MW) loads are often represented at extreme weather, peak, off-peak, and/or light load levels depending upon the type of analysis being conducted. The load levels for studies of the HV and EHV systems are based on the forecasts of diversified peak demand (developed for transmission analysis purposes) provided by AEP's Fundamental Analysis and Economic Forecasting function. These forecasts include both the loads of full requirements customers and customers taking transmission service within the AEP control area. For studies of the subtransmission system, load levels are based on peak demands of individual load areas.

Facility planning studies usually simulate performance during peak load periods because this is the condition that produces the most heavily loaded transmission conditions. There are exceptions due to: 1) pumped storage hydro characteristics, and 2) the fact that the heaviest power transactions often occur at load levels 80-90% of peak. Sensitivity analyses are conducted to investigate the impact of load growth forecasts on the expansion/modification plans being considered. For most studies of AEP's internal system, subtransmission system loads are modeled in order to capture the effects of shunt capacitors, LTC transformers, and the hydro-electric generators that are connected to the subtransmission system. Broader regional and interregional studies generally model loads only at the 138 kV and higher voltage levels.

For near-term operational planning studies, two typical peak load levels are used. One is based on the forecasted peak with a recurrence of once in two years. The other is based on extreme weather with a recurrence rate of once every five years. The load level for an extreme-weather forecast is generally 104-106% of the forecasted peak.

Reactive power (MVar) loads are based on the measured power factor for each load area. It is assumed that reactive correction will be provided as load increases in the future to maintain that power factor. Where future system assessments indicate a need for additional power factor correction, appropriate reinforcements are proposed to meet AEP's design goal that each voltage level is not a reactive burden to its source system. When the impacts of extreme weather forecasts are assessed on the transmission system, the power factor of the incremental load (above the base forecast load) is modeled at 80% because it is assumed that power factor correction is not provided for load that exceeds the forecast.

Power transfer levels modeled in base cases for analysis of the AEP System vary from one study to another depending on the particular focus of the study. The NERC Multi-Regional Modeling

Working Group (MMWG) power flow base cases generally model only committed firm energy commitments. Reliability *First* cases, which are derivatives of the NERC cases, are modified to include additional recently experienced power transfer biases. AEP's base cases, which are derived from these regional models, may require further updates and detail. Often high levels of transfers are simulated to reflect parallel flow conditions reflecting recent experience and in order to assure that probable system bottlenecks are identified.

Generators are normally dispatched to simulate economic operation (lower cost generation 'loaded' first followed by higher cost units) to meet the load demand for system conditions being studied. Most generators will be modeled at or near full output for peak load conditions while some units may be at minimum levels for light load conditions depending upon generation market assumptions.

In addition, for operational planning studies, the generation dispatch reflects scheduled generation maintenance related outages. In some cases, the generation dispatch may be adjusted to more accurately reflect other constraints or typical dispatch levels of the units. Pumped storage units are dispatched in the pumping, generating, or condensing mode, depending on modeled system load level and other typical operating constraints such as generating unit minimum output levels appropriate for the modeled conditions. Emergency dispatch models may also be used to simulate actions taken to relieve transmission constraints or to simulate a response to an extreme condition. In the absence of specific information, non-utility generators are modeled in the same manner as utility generation for transmission study purposes.

Base cases model all transmission facilities in service except for known scheduled maintenance, long term construction outages, or long-term forced outages. These known outages are normally only reflected in operational planning studies. Because it is impractical and unnecessary to represent all interconnected systems in detail, the type of planning study dictates the extent of the interconnected network representation. Thus, an interconnection study involving the bulk transfer of power between two power systems not only would require sufficient detail of the bulk transmission in each participating system but also would include sufficient detail and/or equivalent representation of other interconnected systems to assure proper analysis of critical elements.

Sufficient modeling of neighboring systems is essential in any study of the AEP bulk transmission system. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the NERC MMWG power flow library or the neighboring company itself. In general, sufficient detail is retained to adequately assess all outages and changes in generation dispatch, which are contemplated in the particular study. Other areas are usually reduced to a mathematical equivalent.

With the power flow base cases described above, the study engineer develops scenarios that are surrogates for a wide range of possible conditions. Numerous facility outages and power transfers occur daily in the interconnected network. It would be impractical to simulate all such possible conditions in planning studies. In order to establish a manageable set of base case scenarios, historical data and experience are employed. Although history is not a perfect indicator of the future, it provides valuable information to benchmark the base case models. For future power flow base cases, further adjustments are made to reflect forecasted load levels, expected facility changes, and projected power transfers, as well as emerging trends that will affect historical power flow patterns.

Power flow models described above are the most frequently used models for transmission planning studies. Transient stability and short circuit studies are also used to evaluate the system performance during and immediately following fault conditions on the transmission system. The network configurations used in the power flow models also provide a starting point for transient stability and short circuit studies. In addition, for transient stability studies, additional impedance and electromechanical detail of generators and their controls are included. Three-phase models of the power system are employed to study single-phase switching and other unbalanced operating configurations.

### **3. PERFORMANCE STANDARDS**

Performance standards provide the basis for determining whether system response to contingency analysis is acceptable. Depending on the nature of the study, one or more of the following five types of performance standards will be applied: thermal, voltage, relay, stability, and short circuit.

In general, system response to contingencies evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance. Each type of performance standard is described in the following discussion.

#### **3.1 Thermal Limits**

Thermal ratings define transmission facility loading limits. Normal ratings are generally based upon no abnormal loss of facility life or equipment damage. Emergency ratings accept some loss of life or strength, over a defined time limit for operation at the rated loading level. The thermal rating for a transmission line is defined by the most limiting element, be it a conductor capability, sag clearance, or terminal equipment rating. When a line is terminated with multiple circuit breakers, as in a ring bus or "breaker and a half" configuration, it is assumed that the line flow splits equally through the terminal equipment unless one breaker is open. Ratings in power flow simulations normally assume all breakers are in service.

Normal ratings are applied in all planning and operational studies for base and transfer conditions without outages. In long-term facility planning studies, the thermal limits are dependent on the system and time frame being evaluated. For testing the bulk transmission system (exclusive of power transfer capability studies described in subsection 4.3), facility normal ratings should not be exceeded for single contingencies. In contrast, for area transmission studies, the emergency ratings of HV facilities should not be exceeded for single contingencies. This important distinction between bulk transmission (EHV) facilities and area transmission (HV) facilities stems from differences in function and the greater variability and uncertainty associated with bulk transmission loading patterns. Therefore, to compensate for this effect, a greater margin is provided for EHV facilities by using the more conservative normal rating. For testing involving severe multiple contingencies (such as NERC Category D), potential overloads normally would not require immediate corrective action unless the post contingency conditions would lead to widespread, uncontrolled outages.

For operational planning, emergency ratings are used to assess performance following single contingencies but before any applicable operating procedures are implemented. Following an

outage, system operators will implement available operating procedures in order to reduce all facility loadings below their respective emergency ratings, should the next contingency occur. The application of these facility loading limits is summarized in Table 1. Where the ability to operate at loading levels up to emergency ratings is critical to acceptable system performance, the emergency ratings are verified. This is particularly important in the case of transmission lines, which may be limited by sag clearances.

Most thermal ratings are defined in amperes. However, transmission planning studies use ratings expressed in MVA, based on the ampere rating at nominal voltage. When voltages during testing deviate considerably from nominal, the MVA rating is adjusted for the voltage deviation from nominal.

<b>Table 1</b>			
AEP Transmission Planning Criteria (Steady State System Performance)			
Transmission System Condition	Maximum Facility Loading (Rating)	Minimum Bus Voltage	
		EHV	HV
All facilities in service	Normal	95%	95%
One facility out of service	Emergency (1) Normal (2) Emergency (3)	90%	92%
Two facilities out of service	Emergency	90%	92%
(1) Operational planning criteria before operating procedure implemented. (2) Facility planning criteria (EHV facilities). (3) Facility planning criteria (HV facilities).			

### **3.2 Voltage Limits**

Voltages at transmission stations should be at or above the values listed in Table 1 to reduce the risk of system collapse and/or equipment problems. In addition, voltages at generating stations below minimum acceptable levels established for each station must be avoided to prevent tripping of the generating units. High voltage limits are specific to particular pieces of equipment, but are typically 105% of nominal. Post-contingency voltage drop limits are utilized to prevent voltage instability, which could result in system voltage collapse. AEP will investigate any potential voltage drop above 6% for voltage instability. Voltage drops above 10% are considered violations of AEP's criteria and should be avoided. PJM planning and operational analyses utilize a similar but slightly more conservative approach in applying voltage limits across the AEP system. Refer to the PJM Manual for Transmission Operations (M3) for further detail.

### **3.3 Relay Trip Limits**

Relay trip settings, selected primarily for fault conditions, could be reached in some cases during contingency loading conditions or transient power swings. These relay trip settings are evaluated in operational planning studies, as well as longer term studies, to determine whether adjustments are needed. If it is not practical to revise the setting, subsequent planning studies must recognize that the line could trip due to the resultant contingency loading condition. Facilities may also be limited by relay limits if the relay trip setting is not at least 50% above the emergency thermal rating.

### **3.4 Stability Limits**

Stability limits can be of several types and are characteristic of any power system. More than one type of limit may impact power system operation, but often only one type of limit is most constraining.

The steady-state stability limit ( $P_{MAX}$  in Figure 3.1) is the point at which no more power can flow through a system without precipitating a voltage collapse. This limit is often related to heavily loaded systems where even small perturbations, such as the normal adjustment of generator output to match load, could cause system collapse. Steady-state stability limits are typically evaluated using power vs. voltage (PV) curves or power vs. angle curves, for individual lines or transmission interfaces. In planning studies, a loadability limit is defined, which includes a safety margin of 5-10% below the theoretical maximum power flow.

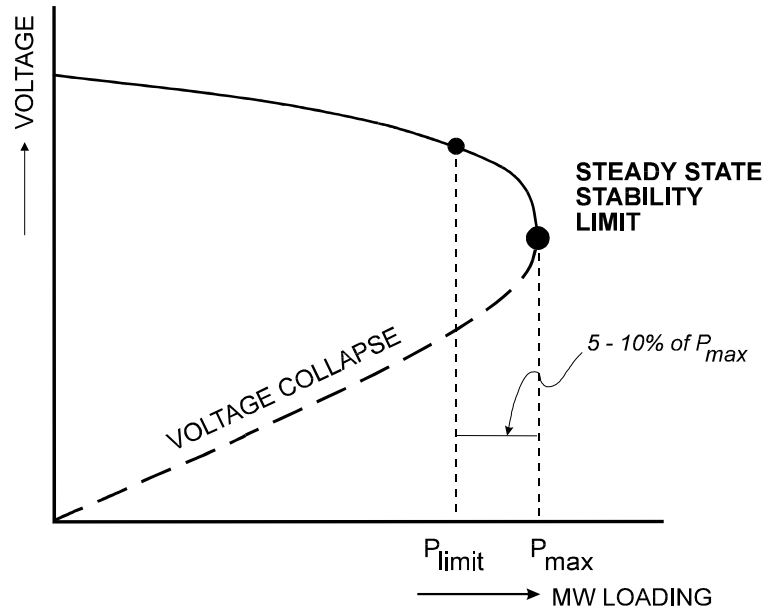


Figure 3.1

Transient stability refers to a power system's ability to remain in synchronism following a disturbance, such as a short circuit. Facilities must be planned and operated so that all generating units remain stable through the transient period regardless of the plant's output level prior to the disturbance. Also, transient voltage dips at generating stations below established minimum acceptable levels, and for significant durations, must be avoided to prevent tripping of the auxiliary loads, which in turn, could trip generating units.

Oscillatory stability refers to a power system's ability to damp out electromechanical oscillations (or power swings) in the 0.1-3.0 Hz range. Oscillatory modes within this range inherently exist on any power system. Oscillatory instability is manifested in terms of sustained or growing oscillations in various electrical quantities observable at power plants and on the transmission system, following a disturbance, or a routine network operation such as load ramping. These oscillations must be suppressed within seconds to prevent potential equipment tripping and damage. The oscillatory instability limit is defined as the power level beyond which one or more generators or groups of generators continue to exhibit one or more sustained modes of oscillation beyond a reasonable time limit. Generally, this limit is not dependent on the size of the disturbance or the period of the mode.

Any sustained or growing oscillation that persists beyond a reasonable time period indicates that the stability limit has been exceeded and represents unacceptable performance.

### **3.5 Short Circuit Limits**

Short circuit limits are also an important aspect of system performance, since the extremely high, short duration currents that accompany system faults will impose considerable stresses on network elements. Circuit breakers must be capable of interrupting the anticipated fault currents in the shortest possible time. Failure to interrupt these currents may lead to catastrophic equipment damage and endanger human life. Short circuit levels increase as network reinforcements are implemented or new generating units are added to the system. Therefore, short circuit levels must be reviewed periodically so that inadequate equipment can be replaced or upgraded, or a mitigation procedure developed.

## **4. TRANSMISSION TESTING CRITERIA**

### **4.1 Steady State Testing Criteria**

The planning process for AEP's transmission network embraces two major sets of testing criteria to ensure reliability. The first set, which applies to both bulk transmission and area transmission assessment and planning, includes all significant single and double contingencies. The second set, which is applicable only to the bulk transmission system, includes more severe multiple contingencies and is primarily intended to assess the potential for system cascading.

For bulk transmission planning, the testing criteria are deterministic in nature; these outages serve as surrogates for a broad range of actual operating conditions that the power system will have to withstand in a reliable fashion. The planning for area transmission supplements the deterministic criteria with a probabilistic approach to performance assessment. Additional applications of probability concepts to the transmission planning process are described at the end of this section.

#### **4.1.1 Single and Double Contingencies**

The testing criteria for area transmission are usually limited to single-contingencies for the LV transmission system (23 kV to 88 kV) while both single and double-contingencies are tested for the HV transmission system (230 kV, 161 kV, 138 kV and 115 kV). This contrasts with the criteria for the EHV transmission system where more severe multiple contingencies are also considered. This difference is appropriate because of the limited geographical scope of area transmission systems as compared to the broad geographical scope of bulk transmission systems, with the attendant increase in system variables and potential for blackouts affecting a large geographical area should a cascading outage of the bulk transmission system occur. In essence the testing criteria represent a continuum where more stringent tests are applied as the geographic extent of the area and the number of customers and amount of load increase. In principle, this approach strikes a rational balance among risk, reliability and the cost of system reinforcement.

Contingencies include the forced or scheduled outage of generating units, transmission circuits, transformers, and/or other equipment. In general, a single contingency is defined as the outage of any one of these facilities. Due to the interconnected nature of power systems, testing includes outages of facilities in neighboring systems. A single facility is defined by the arrangement of automatic protective devices. Generally, double circuit tower outages, breaker failures, station outages, common right-of-way outages, and other common mode failures have substantially lower probabilities of occurrence than the outage of a single transmission facility and are, therefore, not considered single contingencies.

Double contingencies, being a more severe test of system performance, are used as a surrogate for the significant uncertainties that are inherent in the planning process. A double contingency can be defined as an outage of any two facilities. Double contingencies can be categorized by industry standards as either N-2 (an overlapping outage of two facilities with no corrective action following the first contingency) or N-1-1 (this category allows system adjustments after the initial outage). N-

2 double contingency analyses are frequently applied in facility planning studies of the bulk transmission and N-1-1 contingencies are applied to the HV area transmission systems of AEP. Typically, these tests provide additional insight regarding the need for transmission system enhancements.

For facility planning purposes, contingencies result from scheduled maintenance and/or forced outages. Double outages are generally viewed as separate events that overlap in time. Each contingency is tested with the system load level, generation dispatch, and generating unit outages which would be most severe, but still credible, for that particular contingency.

Single and double contingencies are tested with firm import and export transactions, third party transfers, and the expected level of opportunity transfers (or expected generation market activity) as a base condition. The import scenarios assessed assume planned imports plus an additional level of imports necessary to assure that the eastern AEP zone loss of load expectation will be no greater than one day in ten years. Furthermore, since the availability of off system resources is uncertain, the transmission system must be capable of importing these resources across a limited number of interfaces when these resources are not available from one or more directions. Sensitivity studies are also normally conducted for a range of opportunity transfers and generation dispatches as well as extreme weather conditions.

Operational planning studies consider up to two key outages in effect prior to the next (third) contingency. It is assumed that all operator adjustments required for the prior outages have been implemented. Uncertainties such as generation availability and dispatch, load forecast error and load diversity are also considered. The number of prior outages depends on the strength of the transmission system and the number of variables to be considered in developing effective operating guidelines. Clearly, as the number of concurrent contingencies increases, it will become increasingly difficult to meet the required performance limits (see Section 3), even with special operating procedures.

The number of outages actually occurring on the system can exceed the number assumed for study purposes. Operational planning engineers evaluate those conditions, as needed.

#### **4.1.2 Severe Multiple Contingencies**

The more severe reliability assessment criteria required in NERC Reliability Standards are primarily intended to assess the risks for uncontrolled area-wide cascading outages under adverse but credible conditions. AEP, as a member of ReliabilityFirst, plans and operates its bulk transmission system to meet the criteria. However, new facilities would not be committed on the basis of local overloads or voltage depressions following the more severe multiple contingencies unless those resultant conditions were expected to lead to widespread, uncontrolled outages.

In operational planning studies, the purpose of studying multiple contingencies and/or high levels of power transfers is to evaluate the strength of the system. Where conditions are identified that could result in significant equipment damage, uncontrolled area-wide power interruptions, or danger to human life, operating procedures will be developed, if possible, to mitigate the adverse effects. It is

accepted that the defined performance limits could be exceeded on a localized basis during the more severe multiple contingencies, and that there could be equipment damage, increased loss of equipment life, or limited loss of customer load. Normally, operating procedures to mitigate uncontrolled area-wide power interruptions are only used on an interim basis until facility additions can be put in place to restore acceptable reliability levels.

In carrying out operational or facility planning studies, it is recognized that there are many protective and special controls on the system that must operate properly when an event occurs. These controls include but are not limited to: protective relays, breaker failure schemes, quick reactor or capacitor switching, rapid generating unit runback, automatic motor operated disconnects, and emergency generator tripping. The misoperation of any of these controls may result in equipment damage, but should not result in widespread power interruptions or danger to human life.

#### **4.2 Stability Testing Criteria**

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 the power flow testing described above.

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 Appendix B transient stability disturbance testing criteria 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 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 affects 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. The measures of acceptable performance for each type of stability performance problem are discussed in Section 3.4.

AEP 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 of Appendix B 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 Appendix B 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.

### **4.3 Power Transfer Testing Criteria**

The power transfer capability between two interconnected systems (or sub-systems) with all facilities in service or with one or two significant components out of service, indicates the overall strength of the network. Many definitions of power transfer capability are possible, but uniformity of definition is highly desirable for purposes of comparison. Furthermore, transfer capability, however defined, is only accurate for the specific set of system conditions under which it was derived. Therefore, the user of this information needs to be aware of the conditions under which the transfer capability was determined and those factors that could significantly influence the capability.

AEP has adopted the definitions of transfer capability, published by NERC in "Transmission Transfer Capability", dated May 1995. The most frequently used transfer capability definition is for First Contingency Incremental Transfer Capability (FCITC) and is quoted below from the referenced NERC publication:

#### **First Contingency Incremental Transfer Capability**

"FCITC is the amount of power, incremental above normal base power transfers, that can be transferred over the transmission network in a reliable manner, based on the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.
2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit, and
3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any

post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits."

First Contingency Total Transfer Capability (FCTTC) is similar to FCITC except that the base power transfers (between the sending and receiving areas) are added to the incremental transfers to give total transfer capability.

While the first contingency transfer capabilities are the most frequently used measure of system strength, transfer capabilities also can be calculated for "no contingency" and "second contingency" conditions.

In April 1996 the Federal Energy Regulatory Commission issued two rules – Orders No. 888 and 889. Two aspects of these rules are "open access" to the transmission systems of integrated utilities and the posting of Available Transfer Capacity. The ability of a transmission system to permit power transfers is defined by several commercial terms, namely:

- Firm Available Transfer Capacity (ATC)
- Firm Total Transfer Capacity (TTC)
- Non-firm ATC
- Non-firm TTC
- Transmission Reliability Margin (TRM)
- Capacity Benefit Margin (CBM)

These commercial terms are often confused with the reliability terms such as FCITC and FCTTC. The ATC/TTC values provide an indication of the ability of the transmission system to support incremental transfers while accounting for TRM and CBM. Firm ATC is the level of additional transfer capability remaining in the physical network for further commercial activity over and above existing commitments, and purchases of firm ATC will have service priority equal to AEP's native/network load. Since AEP is part of PJM, the ATC values for the entire PJM footprint are determined by PJM. These ATC/TTC values are calculated for transactions between PJM and directly connected control areas and for selected commercially viable paths across the PJM footprint. ATC values are the lesser of network capability or contract path capacity (i.e., the total capability of interconnections to a neighboring control area). Firm TTC is the sum of firm schedules and/or reservations plus the firm ATC values for a particular path. Non-firm ATC values are calculated in a manner similar to that used to calculate the firm values, except that both firm and non-firm transactions are included in the calculations.

TRM is the amount of transmission margin required to ensure that the transmission network is secure under a range of uncertainties in operating conditions. These uncertainties include generation unavailability, load forecast error, load diversity, unknown outages in neighboring systems, and variations in generation dispatch. The TRM is applied directly to AEP facility ratings for calculations of firm ATC/TTC. In instances where the transmission system is voltage or stability limited, system performance surrogates, such as line loadability or area voltages, are used as capability measures.

CBM is the amount of transfer capability required by Load Serving Entities to ensure access to generation from interconnected systems to meet generation reliability requirements. The total AEP CBM value is based upon generation reserve requirements and the ability of the AEP transmission system to import emergency resources to achieve a loss of load expectation of no more often than one day in ten years. This transmission capacity is in addition to any planned imports. CBM is subtracted as fixed MW amounts from AEP facility ratings.

The methodologies employed to calculate these values are consistent with the NERC and RFC Standards.

#### **4.4 Probability Concepts Applied to Area Transmission Assessment**

The evaluation of the need for area transmission reinforcements is based on probabilistic techniques, applying the principle that:

$$(\text{Risk}) \times (\text{load affected}) = \text{Constant}$$

The constant, which represents a threshold value for determining reinforcement need, is selected based on engineering judgment and then applied uniformly for all area transmission analyses. In selecting the constant, some risk of undesirable performance is accepted, but this risk is held to a manageable level. This principle also implies that for larger load areas less risk is taken and vice versa.

The goal of the probabilistic approach is to quantify the risk (via a project index) of disrupting service to an area due to contingencies. Project indices above the threshold are then used to justify the need for improvement programs. There are three steps in the development of a project index, namely:

- a. calculate risk indices
- b. calculate contingency indices
- c. calculate a project index

The risk indices are calculated for each contingency. They are defined by three probabilities:

- i. the probability of a piece of equipment being unavailable due to an outage and its associated restoration time
- ii. the probability of an area load at the time of an outage being at or above the critical level that will cause power supply network problems
- iii. the probability that an overloaded facility will fail and/or a voltage depression will cause a disruption of service

For each contingency, a risk index is calculated as the product of these three probabilities.

The contingency indices are calculated as the products of the individual risk indices and the load affected by each risk index. Where multiple contingencies cause performance violations that require system reinforcement or modification, the project index is the sum of the contingency indices.

The individual project indices are compared with a constant representing a threshold value for determining reinforcement needs. Once a specific project index exceeds this threshold value reinforcement plan and associated cost are developed. The timing for implementations of the various reinforcement plans are then prioritized based on project index and associated cost.

#### **4.5 Other Applications of Probability Concepts**

At this time, probability concepts have made greater penetration into the area transmission planning process than the bulk transmission planning process. This is a reflection of the fact that more of the factors affecting area transmission planning, such as area loads, can be defined probabilistically. Bulk transmission planning, on the other hand, is impacted by a much wider variety and number of interconnected system variables. Many of those variables are difficult to predict in terms of probability distributions.

The following brief descriptions identify some of the ways in which probability concepts are presently being utilized by AEP.

- The interpretation of the applicable regional testing criteria and selection of specific tests implicitly considers probabilities. For example, AEP uses only the more probable single phase fault at 765 kV stations when testing transient stability performance for multiple contingencies. This decision was based on a review of the probability of various types of faults at 765 kV and lower voltages.
- Probability concepts have been used to evaluate operational flexibility. As an example, the "window" for performing scheduled maintenance on critical facilities that serve an area can be determined by examining the area's load duration curve in relation to the expected outage duration of the key facilities.
- Probability distributions of historical parameters, such as power transfer levels and critical facility loadings have been employed to calibrate the assumed base case conditions and thereby improve the realism and quality of study results.
- As part of the process for selecting reinforcement plans, probability concepts are being used. For example, when new station facilities are being added, different station configurations can be studied, using various outage statistics to evaluate the tradeoff between reliability and cost for alternative configurations.
- Probability techniques are used to determine the need for transformer spares.

This is by no means an exhaustive list of probability applications. While universal probability indices, to measure transmission system performance, are not available, there are many aspects of

the planning process where the fundamental deterministic approach is being enhanced by probability techniques.

## **APPENDIX A**

### External Documents that Relate to AEP's Transmission Planning Criteria and Assessment Practices

1. NERC "Reliability Standards" \*
2. NERC "Transfer Capability – A Reference Document" \*

\* NERC website: [www.nerc.com](http://www.nerc.com)

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## APPENDIX B

### AEP TRANSIENT STABILITY DISTURBANCE TESTING CRITERIA

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



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