Administrative Case No. 387

Assessment of Kentucky's Transmission System Vulnerability to Electrical Disturbances

Prepared for

Kentucky Public Service Commission

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TABLE OF CONTENTS

1. SUMMARY

1.1 Introduction

Following the August 14, 2003, blackout that affected the northeastern and midwestern United States, the Kentucky Public Service Commission (Commission) became concerned with the vulnerability of the transmission grid serving the Commonwealth of Kentucky to a similar cascading type of event. A utility task force was formed to advise and assist the Commission with evaluation of the state of the transmission grid. In addition, the Commission sought an independent analysis of the vulnerability of the Kentucky transmission system to a cascading event originating in or near Kentucky and resulting in a widespread electric power grid failure. This report is a result of this process.

The scope of this study is limited to an engineering assessment of the present design of the Kentucky transmission grid as is typically performed using power flow analysis. Except indirectly, as outlined below, the study does not include an evaluation of operating practices, the readiness and/or status of equipment in the utilities' operating centers, the current state or maintenance of transmission line and substation equipment, or the maintenance of rights-of-way. The Task Force reports on the August 14, 2003, blackout identify failures and limitations in operations and maintenance as contributing factors to the collapse. However, this analysis may be useful to the utilities for identifying and prioritizing facilities to be addressed by operations and maintenance personnel.

Although the electric transmission system is complex and continuously evolving, consistent with standard system planning practice, the system conditions analyzed in this study were for summer 2004. As such, the study results documented in this report do not reflect any system upgrades that are scheduled for implementation after the summer of 2004. At the same time, load growth, generation retirements, and other system changes that were not known at the time the case was constructed are not included. However, unless specifically demonstrated otherwise, the general study conclusions will be valid.

1.2 Background

This study uses traditional methods to evaluate the vulnerability of the Kentucky electric transmission system to cascading outages. The North American Electric Reliability Council (NERC), East Central Area Reliability Council (ECAR), Southeastern Electric Reliability Council (SERC), and utilities have established criteria that define transmission system reliability. If a system meets these criteria, it is assumed to be reliable. If it does not, then it is presumed to be potentially vulnerable. The traditional approach was adopted by the Task Force that studied the blackout of August 14, 2003.[1]

As is the case with any report that addresses a technical subject and that also endeavors to reach conclusions that are accessible to non-technical persons we face a dilemma between simplifying

[1] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, page 41, outlines a model-based analysis of the Eastern Interconnection at 3:05 EDT.

and generalizing explanations that may obscure important technical details and providing so much technical detail that our report becomes useless to the broader audience. We are fortunate in this case that the Task Force that studied the August 14, 2003, blackout has produced a fine overview of the North American Electric Power System in Chapter 2 of its report. Rather than attempt to repeat this overview here we simply recommend that the non-expert read these eleven pages. For convenience we have included this chapter as Appendix A. The full report can be downloaded at:

https://reports.energy.gov/

For the purpose of understanding our central conclusion, it is useful to define some of the terms used. We can start with a definition of the extent of the Kentucky transmission system. The following utilities own or operate electric transmission in Kentucky: American Electric Power (AEP), Big Rivers Electric Company (BREC), Cinergy (CIN), East Kentucky Power Cooperative (EKPC), LG&E Energy (LGEE), and Tennessee Valley Authority (TVA). In general, when we talk about transmission lines we are examining lines with voltages above 35 kilovolts (kV). In this study we focused on facilities (lines, transformers, substations, and buses) with voltages of more than 100 kV. We also examined portions of the system that are electrically close[2] to Kentucky.

Another key concept is the idea of a contingency. A contingency is simply an unplanned event occurring on the transmission system that causes the loss of a facility or facilities. These events may be initiated by any number of causes. For example, an animal might get into the equipment, there might be a lighting strike, an operator might make a mistake, etc. The industry classifies these contingencies into categories and specifies expected system response for each category. These categories are described in more detail in the methodology section of this report.

Our study also relies heavily on a base case which is a mathematical model of the transmission system that the utilities expect at a particular instance. The mathematical model is known as a power flow (or sometimes load flow). By modeling the contingencies we think might occur we can predict the performance of the system for these events.

System protection refers to relays, fuses and other devices that protect individual facilities from damage. The basic idea is that the protective device will operate a switch, which is usually a circuit breaker, to remove the facility from service before it is damaged or before it can cause damage. These are similar in function to the fuses and circuit breakers in your home that interrupt a circuit before the wire is damaged or before it can cause damage such as a fire.

Operating procedures are actions that transmission operators can take if they feel that an unplanned event will result in a problem. In general these prescribe actions that can be taken if system conditions warrant preventive action.

We use the term scenario to describe a sequence of events that might be initiated by a contingency that causes criteria exceptions such as overloads and low voltages. The steps in the sequence are determined by the loading and voltages of the facilities following the preceding

[2] For a more technical description of electrically close, see the Study Methodology section below.

steps in the simulation. If the sequence of events stops before "too much" load is lost (or before other specific conditions occur) we conclude that the scenario does not represent a threat of widespread outages. If we can't, then we presume that there is a threat of widespread outages based on the initiating contingency and the scenario. It is worth noting here that proving that the system is not vulnerable to widespread outages presents the logically questionable endeavor of attempting to prove a negative. We attempt to avoid this trap by adopting study criteria based on industry criteria and attempting to show that all the contingencies fall inside or outside these criteria.

1.3 Central Conclusion

Our study shows that the potential for widespread electric power grid failure from events originating in or near Kentucky cannot reasonably be precluded. This conclusion is highly technical in nature, relies on certain assumptions, and is based on the number of events (contingencies) we identified where we cannot reasonably dismiss the possibility of widespread outages. While we must conclude that we cannot reasonably exclude the potential for widespread electric power grid failure based on the results of this broad study, it may be that detailed review by the utilities or others will show that the possibility can be precluded. It would not be unusual to expect that detailed studies by the utilities that have more intimate knowledge of their systems, along with more detailed models, would result in the elimination of many, if not all, of the base case scenarios. Alternately, if scenarios cannot be eliminated, then mitigation measures such as changes to system protection, system operating procedures, or new facilities would be investigated. If adopted, these changes might eliminate the reasonable possibility of widespread outages. It is important to note that there is nothing in this study that suggests that the possibility of widespread outages is any different now than it has been historically. For perspective, it is worth noting that we studied over one million initiating events, directly simulated nearly 100,000, and have concluded that all but fewer than 1,200 can be precluded from causing widespread outages. Of these 1,200 scenarios, fewer than 150 are normal or "base case" scenarios. The remaining scenarios are under conditions such as high transfers or import scenarios that were considered extreme grid operation scenarios.[3] Although it would take similar studies in other regions to demonstrate conclusively, we have no evidence that the possibility of widespread outages is any worse in Kentucky than anywhere else in the Eastern Interconnection. To the contrary, because Kentucky has generating sources that meet or exceed the load in Kentucky, it is reasonable to surmise that Kentucky is less vulnerable to widespread outages. The US – Canada Power System Outage Task Force observed that one reason why some areas did not blackout on August 14, 2003, were that they had sufficient generation to meet load.[4]

2. STUDY METHODOLOGY

With the exception of TVA, the Kentucky utilities are members of the East Central Area Reliability Council (ECAR). The utilities' planning staffs adhere to and follow the procedures and methods established by ECAR, the Southeastern Electric Reliability Council (SERC), and

[3] There was considerable discussion of the probability of these scenarios. If these scenarios occur frequently, the exposure to widespread grid failure is higher than if they do not.

[4] U.S.-Canada Power System Outage Task Force, Interim Report: Causes of the August 14th Blackout in the United States and Canada, November 2003, discussion on page 50 relating to Phase 7 of the blackout.

the North American Electric Reliability Council (NERC). These procedures are designed specifically to address widespread blackout and cascading situations. Following the August 14, 2003, blackout, numerous recommendations were made by the Study Task Force to strengthen and enforce these requirements. The industry is considering these recommendations and adopting some.

2.1 Direct Analysis

This study uses traditional methods to evaluate the vulnerability of the Kentucky electric transmission system to cascading outages. NERC, ECAR, SERC, and the utilities have established criteria that define transmission system reliability. If a system meets these criteria, it is assumed to be reliable. If it does not, then it is presumed to be potentially vulnerable.

The traditional approach was adopted by the Task Force that studied the blackout of August 14, 2003.[5] As we discuss below, loss of load is allowed for all but Category A and B NERC contingencies.[6] However, the criteria clearly state that only planned/controlled[7] loss of load or power transfers is allowed for Category C violations. If unintended subsequent transmission facility outages result from Category C contingencies, the presumption is that a cascading[8] failure cannot be excluded. Although we expend considerable effort analyzing violations of these planning and operating criteria exceptions or "violations" to identify "solutions," the presumption is that there is potential vulnerability whenever there is a criterion violation.

We do not mean to imply that each "solution" we create is an operating procedure or plan that might actually be implemented. We only intend to take our analysis far enough to be able to make a judgment on the potential for violations to cause unintended outages of additional transmission facilities.

On the other hand, even if we identify a "solution," this does not necessarily imply that there should be an automatic action or written procedure to address it. As long as we are convinced

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[5] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, page 41, outlines a model-based analysis of the Eastern Interconnection at 3:05 EDT.

[6] NERC Compliance Templates, Table 1 footnote b) allows Category B contingencies to result in "Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers." A large portion of the effort associated with this report was directed to identifying such conditions so that only conditions that impact the widespread security of the system were considered when reaching our conclusions.

[7] NERC Compliance Templates, Table 1 footnote d) defines "planned/controlled" as follows: "Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems."

[8] NERC Compliance Templates, Table 1 footnote c) defines "cascading outages" as follows: "Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies."

that an operator can recognize and deal with a problem, we will conclude that the situation does not represent a potential cascading situation.

We do not believe that the requirement for "planned/controlled" means it is necessary that a written procedure or automatic action exist for each violation. However, there are some minimum indications that there is no "planned/controlled" response:

A. If the operating utility does not have a priori knowledge that the violation for a Category C contingency exists.

B. If there are widespread overloads, low voltages, or voltage change violations to the point that we believe the operator would be overwhelmed in the time frame that a response would be necessary.

C. If the loss of load or generation is widespread such that we cannot exclude the likelihood of a cycle of load drops and generation overspeed trips.

In any case, our engineering judgment was required to make an assessment of the vulnerability of the system to unplanned and uncontrolled widespread outages. Our focus was to identify conditions where we could not eliminate vulnerability to widespread outages. Further analysis by the utilities may conclude that these events do not lead to widespread outages.

If the violations to the criteria don't meet minimum thresholds, we might conclude that cascading is unlikely. For example, if the violations are restricted to the low-voltage system, or if an overload is small (e.g., below five or ten percent) then we will conclude that the likelihood of cascading is low. While each violation needs to be addressed, in many cases the exceptions to the criteria may be addressed en masse, using judgment and the rules outlined above.

2.2 Indirect Analysis

Evaluation of the intangible practices that make utilities subject to cascading outages is difficult, although after the occurrence of an event that causes significant cascading outages the identifiable cause is often painfully obvious. For example, given First Energy's problems with trees in the rights-of-way reducing the effective capability of its lines, it is improbable that many prudent transmission utilities will overlook a review of their tree trimming practices.

An audit of all the items that might be causative factors in a future blackout incident could be mind-numbing, expensive, and potentially ineffective. Walking all the transmission rights-of-way to find "vegetation management" issues, recalculating all transmission facility ratings, or examining every protective device for poor "Zone 3" settings would surely be expensive, and it might not effectively identify future vulnerabilities. However, the methodology used in this study, along with the cooperation of the utilities involved, provided a good means of indirectly assessing wide areas of concern. If our study identified an area of concern, directed focus on that area can quickly determine if the problem is largely managed or not. Commonwealth Associates, Inc. (CAI) was able to provide interim study results to the utility planning engineers for their review and input during the study process. These responses provided the basis for some of the indirect assessment of the vulnerability of Kentucky's grid that is described with the conclusions.

2.3 Selection of the Criteria

In the project kick-off meeting with the utilities, the key focus of the power flow analysis was to test for NERC Category C compliance. NERC defines Category C as events resulting in the loss of two or more facilities (multiple contingencies). For Category C events the system is to operate within applicable ratings (emergency ratings of equipment and low-voltage conditions) and all generators are to maintain stable operation. However, for Category C events, loss of load (interruption of customer loads) and interruption of power transfers are permitted, *provided that it is in a planned and controlled manner.* There are no criteria that permit uncontrolled cascading outages. Appendix B is the NERC Planning Compliance document.

2.3.1 NERC Category B

To test Category C contingencies (multiple elements), it is first necessary to do a Category B, or 'single' contingency evaluation. NERC defines Category B as an event resulting in the loss of a single facility. As a matter of reference, NERC defines Category A as the system with all facilities in service. NERC requirements, and typical utility practice, are to design the transmission system to maintain continuity of service to all customer loads within the applicable ratings and voltages for Category A (normal system) and B events.

In general, NERC Category B violations occur whenever loss of a single transmission facility (generator, transmission line, transformer, etc.) causes other facilities to overload or violate voltage or stability limits. By utility planning standards, single contingencies should not cause overloads, voltage violations, loss of customer load (with the limited exception of "radial customers or some local network customers, connected to or supplied by the faulted element"), or interruption of scheduled firm power transactions. Nor should they cause unplanned or uncontrolled outages or widespread outages. If a system meets these criteria, it is assumed to be reliable. If it does not, then it is presumed to be vulnerable. This does not necessarily imply that any violation will result in loss of customer load or cascading, but it would identify a vulnerability that needs to be addressed.

Many times, these violations occur on lower-voltage transmission lines, and the utility may have an operating procedure to mitigate the violation. The operating procedure may include opening the overloaded line, changing generation dispatch, or taking other control action.

Before the system can be evaluated for the more severe Category C contingencies, each of the problems identified in the single contingency study must be addressed. For example, if the utility provides an operating solution to a single contingency overload, this operating solution must be modeled every time this contingency is part of a Category C contingency.

Our study methodology was to first run all the single contingencies and present any violations to the appropriate utility for comment. The utility response to these violations typically included one or more of the following comments:

- provided an operating solution.
- provided corrections or updates to line ratings included in the system model.
- recognized the problem as one that has previously been identified and with a future planned upgrade to mitigate.
- no solution provided.

2.3.2 NERC Category C

NERC defines Category C as events resulting in the loss of two or more facilities (multiple contingencies). Category C events represent the next level of probability and severity, generally speaking, for contingency conditions.

One good example of a Category C contingency is the loss of a transmission facility while a generator is out of service (or offline for any number of reasons, such as being uneconomic at certain times). Other examples are the simultaneous loss of two circuits that share a common towerline due to a severe weather event, a single fault on a bus section resulting in two facilities being outaged, or a single fault followed by a breaker failure condition resulting in multiple facilities being outaged. All of these types of multiple-facility outage events tend to be more probable than would be predicted if the single facility outages were taken as independent probabilities, since they are all initiated by a single event.

In particular, for evaluating Category C contingencies, we consider common tower contingencies more probable than other simultaneous outages. The failure of a transmission tower that supports two transmission circuits can be considered a single initiating event that results in the simultaneous outage of two transmission elements. The common tower outage is not considered a Category B (single contingency) event; however, this type of contingency is recognized in the ECAR guidelines and requires utilities to assess their vulnerability to cascading to this event. Therefore, this is one of the first Category C contingencies that we addressed in this study.

2.3.3 Evaluating Category C Violations for Cascading

The system is to operate within applicable ratings (emergency ratings of equipment and low-voltage conditions) and the system is to maintain stable operation for all levels of events. However, for Category C events, loss of load (interruption of customer loads) and interruption of power transfers are permitted, *provided that it is in a planned and controlled manner.*

2.4 Base and Sensitivity Scenarios

The ECAR 2004 summer peak load power flow model was reviewed, updated, and provided by the Kentucky utilities to serve as the basis of this assessment. The base case is a prediction of the expected operation of the grid in 2004 and is based on an extensive planning process that looks at many variables, including, but certainly not limited to, historical system operation, individual utility planning studies, contracts, etc. In an effort to identify the operating edges of the system that may exist beyond the expected base case operating conditions, the study group decided that three additional extreme grid operation scenarios should be modeled. These scenarios include:

A. 6,000 MW transfer from north of Kentucky to south of Kentucky
B. 1,400 MW import into Kentucky
C. 6,000 MW transfer from south of Kentucky to north of Kentucky

Rather than attempt to anticipate which specific generators would participate in any such transactions, we chose to transfer power to and from broad regions north and south of Kentucky. The 'north' and 'south' regions were chosen such that they included sufficient resources to source or sink the transaction without creating any unrealistic impacts. Using these broad regions, generation was proportionally reduced in the receiving region and made available by proportionally reducing load in the sending region. This methodology is consistent with the fact that different areas tend to see peak loads at different times for a number of reasons and that excess generation is often available as a result of these 'non-coincident' peaks. Results obtained in this manner highlight the affects of transfers on Kentucky, without a bias toward a particular system condition that may or may not exist in the future.

2.4.1 Defining the North and South Regions

The 'north' region included Michigan, Indiana, Ohio, Northern Illinois, and the portions of AEP not in Kentucky,[9] for a total of 107,030 MW of load and 108,851 MW of generation.

The 'south' included Tennessee, the Carolinas, Alabama, Georgia, and portions of Mississippi,[10] for a total of 118,460 MW of load and 122,086 MW of generation.

2.4.2 North-to-South Transfer Scenario

We found that the north-to-south transfer caused several facilities to load to 100 percent of their normal ratings, and two facilities were loaded beyond their emergency ratings.

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[9] The control areas in the 'north' were 202 (First Energy), 205 (AEP, except zone 254), 207 (Hoosier Energy), 208 (Cinergy), 209 (Dayton Power and Light), 210 (Vectren), 216 (Indianapolis Power and Light), 217 (Northern Indiana Public Service, 218 (Michigan Electric Transmission Company), 219 (International Transmission Company), and 363 (Northern Illinois).

[10] The control areas in the 'south' were 140 (Carolina Power and Light East), 141 (Carolina Power and Light West), 142 (Duke), 143 (South Carolina Electric and Gas), 144 (South Carolina Public Service), 146 (Southern Company System), and 147 (Tennessee Valley Authority).

We did not attempt to 'correct' the loading on the facilities that did not experience emergency overloads.

2.4.3 South-to-North Transfer Scenario

The south-to-north transfer scenario was constructed by proportionally reducing loads south of Kentucky by 6,000 MW, and generation north of Kentucky by 6,000 MW.[11]

2.4.4 Low Kentucky Generation Scenario

The low Kentucky generation scenario was constructed by proportionally reducing loads north of Kentucky by 1,400 MW and generation within Kentucky by 1,400 MW.

2.5 Construction of the Contingencies

2.5.1 Category B Contingencies

A preliminary list of 1,922 contingencies was generated that included all branches (lines, transformers, switches) within the monitored set. The preliminary list was then refined by grouping together branches that were deemed likely to represent one physical facility. For example, because of historical limitations in power system simulators, three-winding transformers have typically been modeled as three two-winding transformers with equivalent electrical parameters. We also attempted to build line contingencies that were 'breaker-to-breaker.' For example, the individual sections of multi-terminal lines (taps) were, where readily identifiable, grouped together to form one contingency. Real multi-terminal lines generally have circuit breakers only at the substations where the lines terminate, not at the tap point. The result is that a fault on any one section of the multi-terminal line will cause all sections to go out together.

The groups are defined as follows:

a. 3-winding transformers

Any bus such that:

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[11] The case also required one further modification to reduce generation on the case reference bus, Browns Ferry Nuclear (BFN). Transferring large amounts of power (in this case 6,000 MW) long distances results in real power losses that need to be generated somewhere. In the real world, generally speaking, the steady state losses associated with this 6,000 MW transfer would be shared by the generators/utilities participating in the transfer. Ideally, these losses would be compensated on the receiving end of the transfer, since generating them at the sending end means that replacement power also has to travel long distances, leading to more losses.

In a power flow simulation, system losses are replaced by the reference or by area slack buses. The south-to-north transfer induced approximately 250 MW of losses beyond the base case level, much of which is necessary since the transfer source and the replacement generation (at BFN) are both located on the same side of the transfer. This additional 250 MW causes BFN to over-generate. To maintain the 6,000 MW transfer, we compensated BFN by turning on various units in TVA that were not yet at maximum generation.

- there are no bus devices connected (load, generator, shunt, switched shunt) to the bus
- the bus connects only to three transformers
- each transformer connects to a different bus.

b. Multi-terminal line (taps)

Any set of lines such that:

- the bus common to all the branches has no devices connected to it (load, generator, shunt, switched shunt)
- none of the branches is a transformer
- the other end of each branch section must connect to a different bus
- the bus name must imply that it is a tap point. For example, the bus name ends with a 'J' or a 'T.'

c. Multi-section lines

Any set of lines such that:

- the intermediate buses common to adjacent sections have no devices connected to them (load, generator, shunt, switched shunt)
- each intermediate bus must be connected to two, and only two, other buses
- the outside ends of the end sections are not connected to the terminal of a transformer. Multi-section lines are grouped iteratively, grouping together two line sections at a time, until all of the sections of a multi-section line have been included.

d. Generators

Generators were handled as separate contingencies to avoid running them multiple times, once when the generator step-up transformer (GSU) was outaged and once as a bus outage. Replacement generation for generator contingencies was taken from north of Kentucky.

e. Radial circuits

Once the previous four steps were taken, radial circuits were identified. Radial circuits are circuits that connect to the grid in only one place. Said another way, there is no through-flow on a radial circuit. Such circuits may represent a circuit that feeds some load(s), a string of facilities that bring generation into the grid, or a combination of the two.

Once the groupings were complete, we reduced the contingency list by turning off GSU's, all contingencies below 138 kV (to include all transformer contingencies where at least one side is below 138 kV [two-circuit transformers] or two terminals are below 138 kV [three-circuit transformers]), and radials. The resulting list of single contingencies included 1,797 contingencies, of which 1,029 were turned off for the reasons stated above.

2.5.2 Category C Contingencies

a. Common Tower Contingencies

Lines are considered to be on a common tower if they share a common tower for at least five miles. Using data provided by the utilities, including common tower contingency lists and switching diagrams, 87 common tower contingencies were constructed.[12]

b. Double Contingencies

Combining all 768 single and common tower contingencies that were used in the study would result in 294,528 possible double contingencies. This number of contingencies is impractical to analyze with existing tools. As a result, we created a set of double contingencies designed to include only combinations that were likely to be significant. Significant pairs were created by analyzing the effects of every individual contingency on the system and combining any contingencies that impacted one or more common facilities. We defined an impacted facility as:

1. any bus where the voltage changed by at least 3 percent, or
2. any branch (line, transformer) where the flow changed by at least 5 percent from the base case flow.

Using these methods, we generated approximately 29,500 double contingencies.

We evaluated the double contingencies using the following criteria:

- Voltage change violation criterion of 0.1 pu (10 percent)
- Thermal overload violation criterion of 105 percent of the emergency rating (rate 2 in the power flow model) using the assumption that minor overloads are not likely to trip and lead to cascading.

c. Bus Faults and Breaker Failure

A bus fault and breaker failure analysis was performed for all the buses in and surrounding Kentucky. A bus section fault, or bus fault, occurs whenever a bus is tripped for any reason. An example of a bus fault might be an accidental close before grounding equipment was removed following maintenance. (Several years ago a similar event occurred at the San Mateo substation near San Francisco, causing a blackout in the city of San Francisco and neighboring areas.) A bus fault is a NERC Category C event. It should cause only planned outages and

[12] Because they were provided late, TVA Common Tower contingencies were not included.

should not cause cascading. However, since it is caused by a single event (i.e., a fault on a bus section), its probability is relatively higher than unrelated double contingencies.

"Breaker failure" occurs whenever a breaker that should open and clear a fault does not. When this occurs, surrounding breakers open to clear or isolate the problem. While this effectively isolates the problem, it leads to loss of additional equipment.

We began our study by faulting all the buses in Kentucky (and some surrounding buses) with a base voltage of 138 kV or higher. For any bus where there was no violation, no further analysis was necessary. Because the power flow model does not usually include a detailed breaker model, an analysis of each bus where a violation occurred was performed to identify proper breaker failure and bus section contingencies. There were two exceptions to this rule:

- If the bus was included in the power flow model to meet modeling requirements it was not analyzed further because the bus in the model does not map to a real bus in the field.

- If the bus fault caused one or two lines or transformers to be removed it was not analyzed further because this contingency will already be included in our double contingency analysis.

When there were multiple bus sections, a proper contingency was created and an analysis of the switching was performed. If a breaker failure condition was more significant than the underlying bus section fault, a contingency for the breaker failure condition was created.

Forty-five bus section faults cause violations and 23 additional breaker failure contingencies cause violations.

2.5.3 Contingency Evaluation

The power flow study was conducted using CAI's TRANSMISSION 2000® Power Flow (PFLOW) program and its associated Contingency Processor (CP). CP is an automated tool that controls the power flow contingency calculation and summarizes the results.

2.6 Area Monitored

We monitored all facilities in Kentucky for thermal and voltage change violations. Additionally, since Kentucky's transmission system is integrally tied to and affected by its neighbors, we also monitored portions of the region surrounding Kentucky. However, expanding a 'ring' around Kentucky very quickly adds numerous facilities to monitor and evaluate.

To illustrate, the set of facilities that make up Kentucky has approximately 1200 buses, 1600 branches, and roughly 130 ties[13] to neighboring utilities at various voltage levels. On average, the grid tends to have roughly one-and-one-third branches (lines, transformers, switches) for every bus in the system. The ratio in Kentucky is 1.3 (1600/1200). This means that a ring that includes all buses within one branch of Kentucky would add about 130 buses to the Kentucky set, one for each tie line. The next level out, all facilities within two branches, would add another 170 buses. By the time you get to five branches away, you've essentially doubled the number of buses and branches that are being monitored. Obviously, to keep the study focused and manageable, the number of neighboring facilities had to be limited in some reasonable way. We chose to monitor a region that included all facilities within two buses of Kentucky below 345 kV, and all facilities within five buses of Kentucky's system at 345 kV and above.

Facilities below 100 kV were included in the monitored set primarily for the purpose of evaluating the severity of double contingencies. For example, a 161 kV outage that causes low voltages on one hundred 69 kV buses is considered more severe than one that causes low voltages on two 69 kV buses. We did not, however, include these lower-voltage facilities in the study contingency list or attempt to extensively analyze contingencies when results impacted only the lower-voltage system (other than to count them).

3. BASE CASE ANALYSIS

3.1 Category B Contingency Results

Violations that occurred under single contingency analysis had to be resolved prior to continuing with an analysis of Category C contingencies because they were guaranteed to recur in any combination and would mask the true impact of the *combination* of single contingencies. The results of the single contingency run are provided in Appendix B. Elimination of the violations on the 27 branch elements was achieved by using an operating procedure or rating change.[14] We classified these contingencies into three categories: those that had solution problems in the power flow program (cases where the solution interrupted or diverged), those primarily with thermal violations, and those primarily with voltage violations.

3.2 Category C Contingency Results

3.2.1 Common Tower Contingencies

Seven common-tower contingencies resulted in violations.

[13] 'Ties' or 'tie lines' can refer to any facility connecting two neighboring utilities. Common tie line facilities include transmission lines, transformers, and bus ties within substations.

[14] For thermal violations less than 105 percent of the emergency rating, we simply increased the rating of the facility to eliminate the overload. This is valid since we define a significant (thermal) impact in the double contingency analysis as one that causes a violation of more than 105 percent. As a result, the single contingency violation is suppressed while still allowing any significant thermal violations to appear in the double contingency analysis.

3.2.2 *Double Contingencies*

Of the 29,500 double contingencies initially created, 809 caused 2,300 various significant study criteria violation(s).[15] Each of these simultaneous independent outages was solved with full power flow controls to take into account that system adjustments are allowed between the two outages. Because NERC criteria do not allow for adjustment following the second independent outage, our results will tend to predict fewer subsequent criteria violations than might actually occur.[16]

We have automated the process for analyzing criteria violations to assess the potential for cascading. This tool provides direction to engineers and analysts looking for procedures or for identifying load dropping to prevent violations.

The Cascade Analysis tool runs an arbitrarily defined contingency and checks the results against the user-specified criteria to determine if the contingency is likely to lead to a subsequent facility loss. If a subsequent loss is indicated, the loss is simulated in addition to the contingency. The process repeats until the case solves without violations.

The following study criteria were used to generate this report:

Thermal Overload Criterion: 105%
Low Voltage Criterion: 0.9 pu
Voltage Change Criterion: 0.1 pu

For contingencies that cause thermal overloads or low voltages, the next outage is determined by identifying the worst overload (as a percent of rating), or, if there are no thermal violations, by dropping load at the bus with the lowest actual voltage. Only one facility is added to the list of outages per iteration. This process is repeated until there are no further criteria violations.

We used 105 percent of the emergency overload to determine when to trip a line. This is an assumption because, unlike the circuits in your home, transmission lines do not have protective devices that automatically trip them when they exceed their emergency ratings. Frequently lines will remain in service for some time with loading in excess of their ratings. ECAR utilities have frequently used a 130 percent trip level. We could not find any documentation or rationale for this level. We chose 105 percent for the following reasons:

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[15] "Significant" contingencies were defined as any contingency causing a voltage less than 0.9 pu or an overload that exceeded 105% of any facility's emergency rating.

[16] In our judgment this assumption is well within the study accuracy. Any addition criteria violations that might be found by solving the second contingency pair without full adjustments would not be justified in this study by the extra simulation it would require to make this change (this would double the number of simulations). NERC criteria allow for normal clearing following the second contingency. By definition "normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems." Our interpretation is that normal clearing does not include automatic adjustments for transformer taps and area interchange.

- The most compelling reason is that the rating should be accurate. If a rating is too high, then there is a risk of damage before the rating is reached. On the other hand if the rating is too low, the system is not fully utilized.[17]

- In actual practice on August 14, 2003, key lines tripped at or below their ratings.[18] Examples include Stuart to Atlanta 345 kV, Harding to Chamberlin 345 kV (44%), Hanna to Juniper 345 kV (88%), Starr to South Canton 345 kV (93%), and others.

- The rating increase that is possible based on more favorable weather conditions is limited to about 20 percent. For a standard conductor[19] at 100°C, doubling the presumed wind speed from 2 ft/sec to 4 ft/sec, 4 ft/sec to 8 ft/sec, and then from 8 ft/sec to 16 ft/sec results in rating increases of 17, 22, and 22 percent respectively. These increases in maximum thermal rating values are consistent with our design experience, where we have found that the most one can expect from a rating upgrade is about 20 percent. This sets a maximum that should be considered for the overload criterion.

- Particularly when voltages become depressed, distance relays can sense high load currents as faults and trip at or below line thermal ratings. On August 14, 2004, 14 lines tripped for this reason.[20] While not all tripped below emergency ratings, many did.

Although we have not made an organized effort to verify our observation we note that a relatively low overload trip criteria seems to have a minimal impact on the results because most often (over 80 percent of the time) our cascade analysis shows that while a scenario may result in load loss, it does not spread and lead to widespread outages. Consequently choosing a high cut-off certainly would exclude some contingencies that should be considered, but a low cut-off does not create unrealistic scenarios. We chose 105 percent instead of 100 percent because five percent is at the approximate limit of the engineering precision to which ratings can be calculated due to uncertainties in predicted wind speed, temperature, and other effects.

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[17] Southwire Company Overhead Conductor Manual, First Edition, Southwire Company, One Southwire Drive, Carrollton, Georgia, 30110, 770-832-4242, Copyright 1994, page 7.3 – "The maximum allowable phase current is a major component of the maximum allowable conductor temperature. The determination of the maximum allowable conductor temperature (i.e. rating) is extremely important. To err on the liberal side in making this determination may cause loss of conductor strength, physical damage to the hardware, increase of conductor sag, (decrease clearance) beyond acceptable limits, or excessive line loss. To err on the conservative side can cause unwarranted limitation of power transmission, resulting in great financial loss to the utility."

[18] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Page 57-58

[19] Southwire Company Overhead Conductor Manual, First Edition, Southwire Company, One Southwire Drive, Carrollton , Georgia, 30110, 770-832-4242, Copyright 1994, page 7.18, Table 7.5

[20] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Page 81

For contingencies that cause the power flow to diverge, or if any step taken to relieve a violation as discussed above causes divergence, load is dropped at the bus with the lowest voltage and another attempt is made to solve the case. If the lowest voltage bus does not have load, then each bus connected to the low voltage bus is checked for load. The neighboring buses are prioritized according to the impedance that connects each of them to the lowest voltage bus. The lowest-impedance connection is checked first, the next highest impedance next, etc., until all neighboring buses have been checked. This process is repeated until the case solves, at which time the case is checked for criteria violations as described above, or until the tool cannot locate any neighboring buses with load. The tool checks for load out to four buses away, as necessary to locate a load. If no load is located within four buses of the lowest voltage bus, the analysis is stopped and a message is generated to indicate that this has occurred.

Finally, if after completing the above process, a bus(es) was identified that experienced a large voltage drop despite there being no actual criteria violations, a message is generated indicating that the bus(es) might still be in danger of leading to further cascading due to voltage collapse.

The next step in reducing the results was to identify the most critical contingencies in order to provide the Commission with a priority list of significant contingencies, ordered from most to least significant. Rather than simply rank the Category C results from worst to best – which would have just listed 809 double contingencies and their respective impacts – we focused on identifying the root causes of the violations we observed.

To do this, each single contingency was examined to determine how many violation-causing double contingencies it participated in, noting the severity of each of those contingencies. A severity index was developed by summing the total amount of load dropped by every combination of each contingency. For example, if contingency A combined with four other contingencies that caused violations, two of which led to the loss of 250 MW and two of which led to no load loss, the index for contingency A would be 250 + 250 + 0 + 0 = 500 MW.

3.2.3 Bus Faults and Breaker Failure

Bus Faults and Breaker Failure contingencies that caused criteria exceptions were analyzed both with the cascade analysis tool and by hand. Of the combined total of 45 bus faults and 23 breaker failure contingencies that caused exceptions, 54 met the criteria for significant (105 percent) overloads. Using the Cascade Analysis tool, we eliminated all but 12 as candidates for unplanned or uncontrolled cascading.

3.2.4 Statistical Summary of the Results

A detailed summary of all the results is given in Appendix C. The table below summarizes the important results for the Category C contingencies:

Case	Category C Contingencies Studied	Significant Study Criteria Exceptions	Contingencies Causing Significant Exceptions	Potential Widespread Outage Scenarios
Base	23,890	1,381	674	124
Bus Fault (Base)	380	112	37	10
Breaker Failure (Base)	43	19	17	2
Import	23,533	1,891	836	158
South to North	22,109	3,714	1,979	326
North to South	27,178	8,506	3,154	451

Significant results were identified for subsequent analysis by the Cascade Analysis tool. A contingency was deemed significant if it caused overloads greater than 105 percent on any facility or voltages less than 90 percent at any bus. Contingencies causing only voltage change violations (greater than 10 percent) were not checked for further potential for widespread outages.

3.3 Examples of Automated Cascade Analysis

The procedure that we use to assess whether a contingency that causes criteria violations may result in unplanned or uncontrolled cascading outages can be demonstrated by example in all cases. Note that we do not claim that our tool is absolutely predictive. There is no existing technique consistent with available computing power that would allow anyone to make such a prediction.[21] Instead, we concentrate on eliminating situations that we believe are unlikely to result in uncontrolled or unplanned outages. Some of these may result in significant consequential outages and loss of load, but we have concluded that there is no widespread electric power grid vulnerability associated with these events.

On the other hand, there are situations where we project scenarios for potential unplanned or uncontrolled outages, and we conclude that there is grid vulnerability. While experienced power system engineers may have different opinions about specific elements of the scenarios that we generate, we do not conclude that grid vulnerability exists until ample evidence is produced that unplanned and uncontrolled outages are likely and will impact a significant portion of the power grid. We believe that, upon review, most would agree that grid vulnerability exists.

We assume that the system works as it is designed. We assume that there are no trees limiting line capabilities to below ratings, that there are no protective device trips that cause outages below ratings, that automatic devices or operators identify low voltages and react properly, and

[21] For perspective on our efforts here see, "The Unruly Power Grid," Peter Fairley, IEEE Spectrum, August 2004, Page 28. It states "Crash-testing a grid the way one crash-tests a new car is obviously not an option. And, the only alternative, simulation, is beyond the reach of current technology for a system as complex as the Eastern Interconnection-a system of thousands of generators and tens of thousands of power lines and transformers. Fully assessing just one contingency on the Eastern Interconnection means accounting for more than a billion constraints. Add nonlinear behavior of the sort Thorp models, and the differential equations become unsolvable. 'You couldn't get a computer big enough on this planet to go do that,' says Apt.

that there is time between events to successfully accomplish all the actions that need to be taken. Of course, a less well maintained or operated system would increase the probability that the contingencies modeled would actually occur, thus increasing the overall system vulnerability.

Any power system engineer equipped with a power flow program can verify the analysis by repeating the steps.

4. TRANSFER CASE ANALYSIS

This section briefly describes the special characteristics and results for the transfer cases. These cases included a 1,400 MW import into Kentucky and 6,000 MW transfers across Kentucky in north-to-south and south-to-north directions.

While the analysis for the base case relied heavily on individual review and judgment to determine the procedures to remedy violations, the transfer cases all relied on a more automated procedure using the Cascade Analysis tool. We also switched to solving the power flow with full controls for switched shunts, rather than fixing them to their maximum as we had in the base case.

Whenever the contingency caused violations that were less than the 105 percent overload threshold for considering them to be significant, we simply increased the rating to account for the overload. Note that this was only done for each particular contingency. For all others the rating remained as specified in the case. If a Category C contingency did not cause overloads that exceeded 105 percent, we did not perform an automated cascade analysis.

5. CONCLUSIONS

5.1 Conclusion 1 - System Vulnerability to Category B Contingencies

Based on the results herein, Kentucky's electric transmission grid has Category B (single contingency) study criteria exceptions. Our study found 74 instances of exceptions to the criteria in the base case, 60 instances in the import case, 163 instances in the south-to-north transfer case, and 448 instances in the north-to-south transfer case.

While the analysis did not show any Category B contingencies that we considered likely to cause cascading for the base and import cases, there were four cases from which we could not exclude cascading for Category B contingencies in the south-to-north transfer bias case and five in the north-to-south transfer bias case. Consequently, we conclude that there is a heightened vulnerability when the system is transferring power across Kentucky.

Based on the number of study criteria exceptions for Category B contingencies and the response of the utilities to inquiries about these exceptions, we conclude that utilities do not have all Category B violations totally within their planning/operating criteria. In other words, even in the base case, there are criteria exceptions that should be dealt with affirmatively, but we don't always find clear evidence that this is the case, particularly when the transfer cases are considered. While we are convinced that the utilities have looked at these criteria exceptions, we are not convinced that the knowledge of a criteria exception has resulted in an action to address it. For example, updating of power flow models, development of operating procedures and contingency lists, plans for facility rating upgrades, and plans for capital improvements should exist whenever there is a criteria exception. Especially with the Category B exceptions, we caution that it is easy to make more of this conclusion than is intended: it may be fairly easy to demonstrate that affirmative action has been taken, but the scope of this study was insufficient to identify the actions.

5.2 Conclusion 2 - System Vulnerability to Category C Contingencies

The study found that the Kentucky Grid is vulnerable to unplanned and uncontrolled outages as a result of Category C (multiple contingencies) when operating in either the normal or an import configuration. The raw results include:

- 674 pairs of facility outages that cause significant[22] study criteria exceptions in the base case. There are 124 of these contingencies where we could not reasonably eliminate the possibility of widespread unplanned or uncontrolled outages.
- 836 pairs of facility outages that cause significant study criteria exceptions in the import case. There are 156 of these contingencies where we could not reasonably eliminate the possibility of widespread unplanned or uncontrolled outages.
- 54 bus faults or breaker failure conditions that cause significant study criteria exceptions in the base case. There are 12 of these contingencies where we could not reasonably eliminate the possibility of widespread unplanned or uncontrolled outages.

Areas of the Kentucky system were identified where Category C contingencies will result in significant load loss. This is allowed under the NERC guidelines, provided the loss of load is in a planned and controlled manner. At this time, we do not believe all of these conditions have been studied by the utilities, nor do we believe that there are mechanisms (protective relays or operator actions) in place in all cases to cause the load shedding in a planned or controlled manner. An assessment of the scope or depth of the problem is well beyond the level of detail that can realistically be expected from a state-wide screening study such as this. Utilities have detailed operating procedures, a few of which were discussed and many more that were not discussed during the course of this study. Some detailed operating procedures require their own stand-alone studies to properly and fully analyze. In defense of the utilities, we expect that the design and implementation of such load-shedding schemes and operating procedures may not be easily achieved. However, one of the recommendations from the Task Force reviewing the August 14 blackout was for the utilities to make greater use of undervoltage load shedding.

[22] "Significant" means flows 105% over the emergency rating or voltages less than 90% for this study.

5.3 Conclusion 3 - System Vulnerability to Transfer Conditions

The study found that the Kentucky grid is vulnerable to unplanned and uncontrolled outages as a result of Category B (single) and Category C (multiple) contingencies when operating with either a north-to-south transfer or a south-to-north transfer of 6,000 MW. The raw results include:

- 3,154 pairs of facility outages (NERC Category C) that cause significant criteria exceptions in the north-to-south case. There are 451 of these contingencies where we could not reasonably eliminate the possibility of widespread unplanned or uncontrolled outages.

- 1,979 pairs of facility outages (NERC Category C) that cause significant criteria exceptions in the south-to-north case. There are 326 of these contingencies where we could not reasonably eliminate the possibility of widespread unplanned or uncontrolled outages.

- 9 Category B contingencies that cannot be excluded as reasonable causes for unplanned and uncontrolled outages.

- Normal case overloads that cause criteria violations.

These results imply that the grid is more than twice[23] as vulnerable to widespread outages during a transfer across Kentucky than it is under base case or "normal" conditions.

Detailed analysis of these events found numerous south-to-north case and north-to-south case contingency exceptions where we could not reasonably eliminate the possibility of unplanned and uncontrolled outages. We were sufficiently concerned about the validity of these results that we closely questioned the utility participants. They validated our assumptions and provided information that one facility we were concerned with was the subject of Transmission Load Relief (TLR) procedures for over 400 hours[24] during a two-year period. This same facility caused the initiation of an operating procedure to eliminate the problem at least 229 times[25] over a little more than a four-year time period.

The problems identified in the transfer analysis lead us to conclude that the Kentucky transmission system is not designed for 6000 MW transfers. Operations at these transfer levels result in elevated levels of grid vulnerability. To the extent that these conditions are not normal conditions,[26] system performance under these transfer conditions may be beyond utility/industry planning criteria. These scenarios were considered in this study in an effort to identify the operating edges of the system, and thus, may not be considered planning criteria violations.

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[23] This is a rough estimate based on the ratio of the contingencies in the base case where the possibility of widespread outages could not be excluded to the same figure in the two transfer cases. For the south-north transfer case the ratio is 2.6 and for the north-south case the ratio is 4.3.

[24] MTEP-03, Midwest ISO Transmission Expansion Plan 2003, Report Approved by the Midwest ISO Board of Directors, June 19, 2003, Figure 6.1-4

[25] Data provided by EKPC

[26] There was extensive discussion of the frequency of transfers at the level modeled. It was noted that the industry is aware of the problems and that the frequency of these transfers may be declining.

5.4 Concluding Observations

The following general concluding observations are provided from the initial power flow modeling, testing of Category B contingencies, and Category C contingency testing. These observations do not provide a basis sufficient to suggest or preclude a vulnerability to widespread outages, but they do provide a background for the main conclusions and contribute to the way we evaluated the criteria exceptions that form the basis for our conclusion.

5.4.1 Reactive Power Modeling

In the power flow model provided, the reactive capabilities of some of the generating plants were overstated by the amount of step-up transformer losses. Transmission studies by the utilities or their neighbors could be misleading. Sometimes even good models tend to be optimistic about the amount of reactive power that can be supplied by generating plants. We corrected any found deficiencies in the models prior to proceeding with our study. It should be noted, however, that correcting these deficiencies did not seem to substantially change the results of the Category B testing. We believe that the reactive capability limits are more important for assessing the impact of Category C contingencies. The utilities are addressing this by using explicit models of step-up transformers in power flow models.

5.4.2 Transmission Facility Ratings Accuracy

When queried about single contingency violations in the base case, some utilities reported that the ratings in the model were incorrect. It is important that utilities accurately assess the capabilities of their facilities and that these true capabilities are included in planning and operating power flow models.

5.4.3 Power Flow Model Detail

At the onset of this project, a power flow case was constructed to be the basis of the study. The case was modified from regional models to include detailed models of some of the lower-voltage portions of the network in Kentucky. Some of the utilities included lower-voltage detailed models, while others included their usual equivalent model. For severe outages, equivalents may not respond accurately. In this study there were scenarios where we might have been able to eliminate the possibility of unplanned or uncontrolled outages had detailed models been used. When queried, the utilities did not share our concern. The utilities use detailed power flow models of their systems for their internal studies and will request detailed models of neighboring utilities if they feel the detailed model has a significant effect on the results. Because querying neighboring utilities requires extra effort and because the underlying effects may not always be readily apparent, this makes it difficult to correctly analyze the more severe events (i.e., may require querying utility engineers for their input) and potentially decreases neighboring utilities' awareness of possible problems. While a limited model may have been desirable or necessary when computing power was more limited, more detailed models can now be exchanged without penalty.

5.4.4 *Electronic Definitions of Operating Procedures for Criteria Exceptions*

We believe that contingency definitions need to better reflect known operating procedures. We adopted common and prudent study practices and conducted the initial contingency screening without the implementation of any established operating procedures so that the need for those established operating procedures could be clearly highlighted. To do otherwise would only mask the underlying problems for which those operating procedures were established. However, upon initiation of this study, we requested contingency lists and operating procedures so that these could be readily applied to criteria exceptions that we found. During the initial round of single contingency testing of the system, we identified numerous criteria violations where an operating procedure had not been provided. After these were reported to the utilities, additional operating procedures were identified. It is important that planning and operations and neighboring utilities have accurate, up-to-date operating procedures that can be applied to studies and real-time operations. Based on the fact that some of these procedures were identified after the fact, we question whether the utilities are as up-to-date with these procedures as they might be.

5.4.5 *Adequacy of Schematic Information*

For the base case we reviewed bus section and breaker failure contingencies. Utilities typically do not have these contingencies pre-defined; as such, these have to be developed by analysis of the utilities' switching diagrams. Switching diagrams are required to be filed annually with FERC (Form 715). We typically ask for this information when we initiate a study. The FERC 715 schematic and mapping information was sought from the Kentucky utilities. This request provided information that we needed to complete the study and helped to assess the adequacy and completeness of the information available to planners and operators.

Although our observation here is purely anecdotal and certainly doesn't rise to the level of a major concern, we do feel that it is worth the status of an observation. One of the operating diagrams that was initially provided to us did not include information on certain substations, some of which had violations occur for single contingencies, since by design it only included EHV stations and major non-EHV generating stations. Upon our request, the utility was able to provide the detailed operating diagrams that included information on all transmission stations for all voltage classes in the area of interest, including those with the desired switching information. The utility indicated that although a complete set of detailed operating diagrams are included in their FERC Form 715 filing with FERC, only those diagrams of interest to this study were provided to CAI. In another case a diagram we were provided had an out-dated representation of the switching. No matter how rapidly such drawings might be provided once a problem has been identified, operators and planners cannot be expected to be able to retrieve drawings from engineering in the event of an emergency. Without relevant information on the diagrams, other parties, such as neighboring operators and regulators that have access to this kind of Critical Energy Infrastructure Information, are also lacking information. Our main purpose in making this observation is to emphasize the importance of well designed graphical representations and note that the techniques and procedures necessary to ensure the accuracy of these important graphical representations is an area that would benefit from research.

5.5 Further Consideration

In addition to seeking resolution of the issues that have been identified in the study, there are four items that the Commission may want to consider further. The studies described below would be an aggressive attempt to limit the probability that the Commonwealth of Kentucky will be subject to a widespread area blackout.

5.5.1 Probability of Initiation versus Probability of Cascading

As we have indicated throughout the report, this study uses traditional methods to evaluate the vulnerability of the Kentucky electric transmission system to cascading outages. We have demonstrated qualitatively that there are contingencies that will result in unplanned, but for the most part limited, cascading outages due to failure of transmission facilities. However, we have not provided any quantitative measure of the risk. While there has been much research involving applying probabilistic methods to the analysis of power system reliability, it has been only sporadically applied to production studies. These methods have also almost never been applied to determining the probability of a widespread area blackout. However, we believe a quantitative estimate of the probability of such an event can be developed.[27]

[27] Two components make up the probability that an individual event will result in a cascading failure. First is the probability that an initiating event occurs. For example, for a single contingency we are simply looking at the probability that a given transmission line is out. This is a rather simple concept that can be assigned a quantitative value. Using historical data to assign probabilities to different types of outages, the outage probability can be computed as:

Outage frequency x Outage duration = Probability of Outage

Second is the probability that an event will cascade if the initiating event occurs. The bulk of this study focuses at least qualitatively on this probability. Any event that causes a criteria violation has an associated probability that it will cascade. The probability of a cascading event is, therefore, just the conditional probability that there will be a cascading outage given the probability of the initiating event or:

Probability of Cascading Event = Probability of Initiating Event x Probability of Event Cascade

If the probability of an initiating event can be determined and the probability that an event cascades can be assigned, the probability of a blackout scenario can be computed by summing over all such events.

Note that the computation strategy is achievable. If we assume that the probability of an event cascade is negligible for any event that does not violate the criteria, it is only necessary to compute the probabilities of the initiating events that cause violations. Additionally, if we care to look further, assigning probabilities to events should allow a better ranking with respect to event likelihood. While the traditional categories provide a good guideline, the real world probability of a double generator event with a long line out may be higher than the probability that a single

5.5.2 Protective Device Settings (Evaluation of Zone 3 Relays)

In its requirements of February 10, 2004, NERC directed all transmission owners to evaluate the settings of Zone 3 relays on all transmission lines of 230 kV and higher. In its final report, the Canadian/American Task Force recommended "that NERC broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces." It also recommended that "transmission owners should also look for Zone 2 relays set to operate like Zone 3s."[28]

For several reasons, this recommendation should be followed for the systems operating in Kentucky:

- The Kentucky grid includes a large number of 161 kV and lower-voltage lines that likely have this kind of protection.
- If lines trip for Zone 3 settings before they reach the rating used in the power flow case we examined, the potential for outage will be increased.
- This study identified a significant number of voltage change or low-voltage criteria violations. Low voltages exacerbate the likelihood that Zone 3 will operate incorrectly.

The utilities have reported that they are reviewing these protective device settings.

5.5.3 Transfer Mechanisms

The underlying reasons for over-scheduling transfers across Kentucky should be identified. Once they have been identified, an assessment of the benefits of designing the

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short line has an outage. Currently, we would classify the first event as a Category D, while the later event would be Category B. Directly considering event probabilities would allow the rankings to be directly addressed.

Similar to hydrology's 100-year flood that occurs once every ten years, or more often, or less, it will be necessary to carefully interpret the resulting probability. While it might be nice if the computed number matched the actual occurrences, it is more likely that the resulting quantitative probability will be most useful for comparisons. For example, it is most likely to be useful in comparing year-to-year improvements or one plan verses another, rather than to predict the absolute likelihood of blackouts. To further understand the difficulty associated with computing an accurate absolute probability, consider that the probabilities currently used and the planning and physical facilities that spawn from them are based on human error, weather, or other non-intentioned events. Terrorists, on the other hand, do have intentions and information about the systems they seek to disrupt. In this case, high impact events still take precedence, but are coupled with lower-probability initiating events. If you wished to estimate the increased vulnerability because of organized threats, starting with the ECAR extreme contingency types would initiate the study. The study might then be extended to include random combinations of dependent contingencies (but independent facilities). A contingency dependency screening method like that used in this study could be used to limit the number of contingencies studied (i.e., all combinations of three, then four, then ..., then n facilities are studied) as schedule and budget permit.

[28] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, page 158, Recommendation 21

system to accommodate the transfers can be made. We note that NERC and the industry are aware of at least one significant reason which is due to response factors of facilities that are below the current threshold of granting transmission service.[29]

5.5.4 Periodic Review and Analysis

If only to facilitate communication between the Commission and the utilities, this study should be repeated periodically. In addition, an assessment of the cost and benefits of creating a transmission system that minimizes grid-wide vulnerability should be made. An estimate of the cost to minimize the vulnerabilities, while not trivial, is reasonably obtainable. Although the cost of grid outages, such as the one that occurred on August 14, 2003, is more difficult to obtain and somewhat subjective, it is achievable. Comparing these two relative costs would provide firm direction for Kentucky ratemaking policy.

[29] MISO uses a 5 percent cutoff for the Power Transfer Distribution Factor (PTDF) response factor and 3 percent for the Outage Transfer Distribution Factor (OTDF) response factor. A response factor, particularly a PDTF, might result in a flow change of more than the line rating but less than the PTDF cutoff.

2. Overview of the North American Electric Power System and Its Reliability Organizations

The North American Power Grid Is One Large, Interconnected Machine

The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion (U.S.) in asset value, more than 200,000 miles—or 320,000 kilometers (km) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

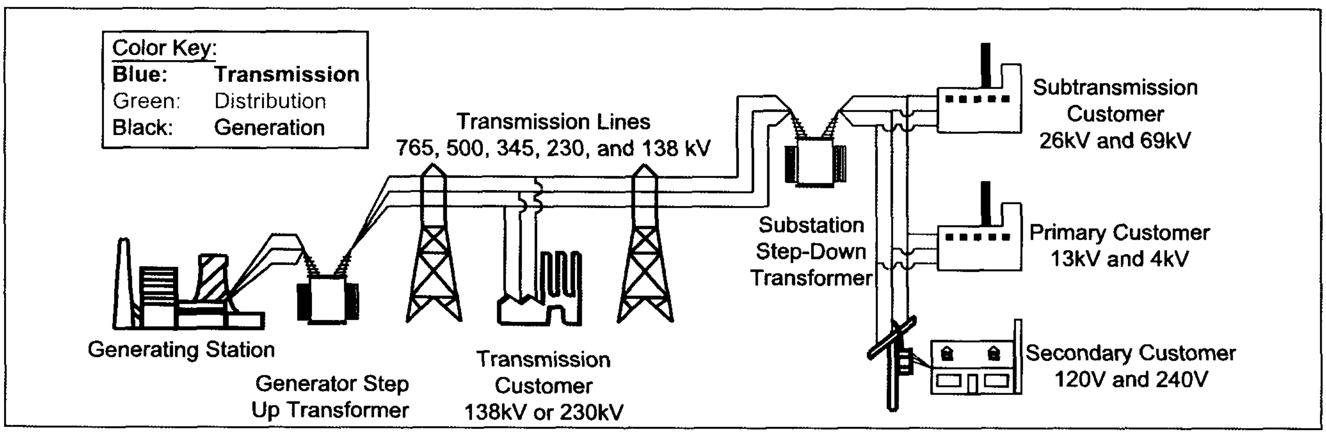
Modern society has come to depend on reliable electricity as an essential resource for national security; health and welfare; communications; finance; transportation; food and water supply; heating, cooling, and lighting; computers and electronics; commercial enterprise; and even entertainment and leisure—in short, nearly all aspects of modern life. Customers have grown to expect that electricity will almost always be available when needed at the flick of a switch. Most customers have also experienced local outages caused by a car hitting a power pole, a construction crew accidentally damaging a cable, or a lightning storm. What is not expected is the occurrence of a massive outage on a calm, warm day. Widespread electrical outages, such as the one that occurred on August 14, 2003, are rare, but they can happen if multiple reliability safeguards break down.

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

As shown in Figure 2.1, electricity is produced at lower voltages (10,000 to 25,000 volts) at generators from various fuel sources, such as nuclear, coal, oil, natural gas, hydro power, geothermal, photovoltaic, etc. Some generators are owned by the same electric utilities that serve the end-use customer; some are owned by independent power producers (IPPs); and others are owned by customers themselves—particularly large industrial customers.

Electricity from generators is "stepped up" to higher voltages for transportation in bulk over

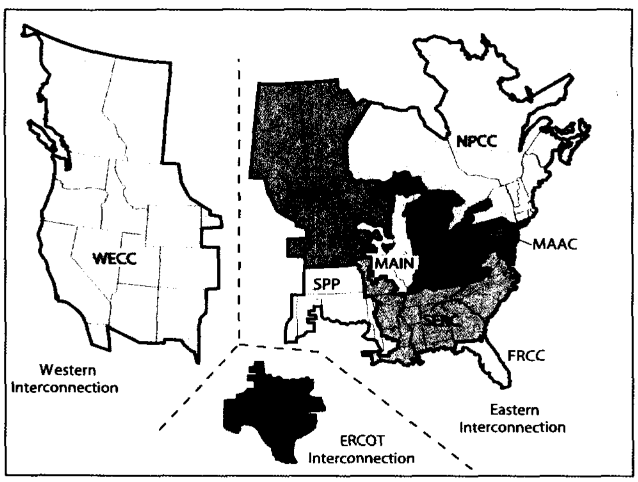
Figure 2.1. Basic Structure of the Electric System



transmission lines. Operating the transmission lines at high voltage (i.e., 230,000 to 765,000 volts) reduces the losses of electricity from conductor heating and allows power to be shipped economically over long distances. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called a power "grid." Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics—along "paths of least resistance," in much the same way that water flows through a network of canals. When the power arrives near a load center, it is "stepped down" to lower voltages for distribution to customers. The bulk power system is predominantly an alternating current (AC) system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another. Some larger industrial and commercial customers take service at intermediate voltage levels (12,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts.

While the power system in North America is commonly referred to as "the grid," there are actually three distinct power grids or "interconnections" (Figure 2.2). The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico. The third interconnection comprises most of the state of Texas. The three interconnections are electrically

Figure 2.2. North American Interconnections



independent from each other except for a few small direct current (DC) ties that link them. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads.

The northeastern portion of the Eastern Interconnection (about 10 percent of the interconnection's total load) was affected by the August 14 blackout. The other two interconnections were not affected.[1]

Planning and Reliable Operation of the Power Grid Are Technically Demanding

Reliable operation of the power grid is complex and demanding for two fundamental reasons:

- First, electricity flows at close to the speed of light (186,000 miles per second or 297,600 km/sec) and is not economically storable in large quantities. Therefore electricity must be produced the instant it is used.
- Second, without the use of control devices too expensive for general use, the flow of alternating current (AC) electricity cannot be controlled like a liquid or gas by opening or closing a valve in a pipe, or switched like calls over a long-distance telephone network.[2] Electricity flows freely along all available paths from the generators to the loads in accordance with the laws of physics—dividing among all connected flow paths in the network, in inverse proportion to the impedance (resistance plus reactance) on each path.

Maintaining reliability is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. The North American Electric Reliability Council (NERC) and its ten Regional Reliability Councils have developed system operating and planning standards for ensuring the reliability of a transmission grid that are based on seven key concepts:

- Balance power generation and demand continuously.
- Balance reactive power supply and demand to maintain scheduled voltages.
- Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.

◆ Keep the system in a stable condition.

◆ Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N-1 criterion").

● Plan, design, and maintain the system to operate reliably.

◆ Prepare for emergencies.

These seven concepts are explained in more detail below.

1. **Balance power generation and demand continuously.** To enable customers to use as much electricity as they wish at any moment, production by the generators must be scheduled or "dispatched" to meet constantly changing demands, typically on an hourly basis, and then fine-tuned throughout the hour, sometimes through the use of automatic generation controls to continuously match generation to actual demand. Demand is somewhat predictable, appearing as a daily demand curve—in the summer, highest during the afternoon and evening and lowest in the middle of the night, and higher on weekdays when most businesses are open (Figure 2.3).

   Failure to match generation to demand causes the frequency of an AC power system (nominally 60 cycles per second or 60 Hertz) to increase (when generation exceeds demand) or decrease (when generation is less than demand) (Figure 2.4). Random, small variations in frequency are normal, as loads come on and off and generators modify their output to follow the demand changes. However, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage generator turbine blades and other equipment. Extreme low frequencies can trigger automatic under-frequency "load shedding," which takes blocks of customers off-line in order to prevent a total collapse of the electric system. As will be seen later in this report, such an imbalance of generation and demand can also occur when the system responds to major disturbances by breaking into separate "islands"; any such island may have an excess or a shortage of generation, compared to demand within the island.

2. **Balance reactive power supply and demand to maintain scheduled voltages.** Reactive power sources, such as capacitor banks and generators, must be adjusted during the day to maintain voltages within a secure range pertaining to all system electrical equipment (stations, transmission lines, and customer equipment). Most generators have automatic voltage regulators that cause the reactive power output of generators to increase or decrease to control voltages to scheduled levels. Low voltage can cause electric system instability or collapse and, at distribution voltages, can cause damage to motors and the failure of electronic equipment. High voltages can exceed the insulation capabilities of equipment and cause dangerous electric arcs ("flashovers").

3. **Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.** The dynamic interactions between generators and loads, combined with the fact that electricity flows freely across all interconnected circuits, mean that power flow is ever-changing on transmission and distribution lines. All lines, transformers, and other equipment carrying electricity are heated by the flow of electricity through them. The

Figure 2.3. PJM Load Curve, August 18-24, 2003

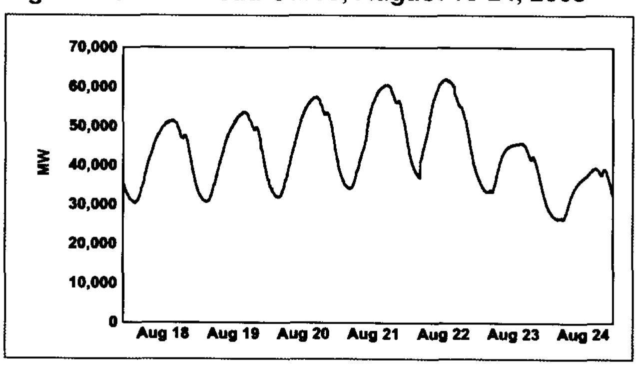
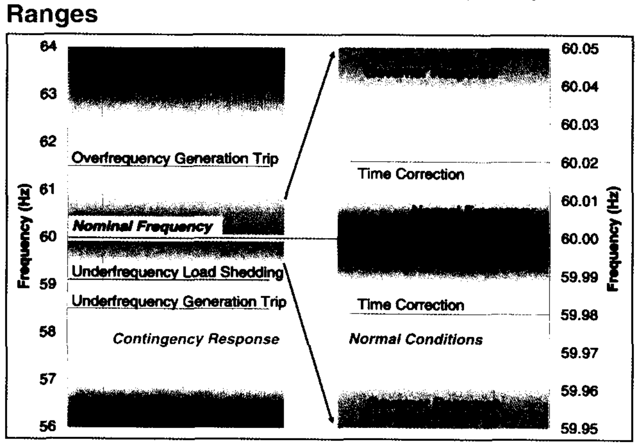


Figure 2.4. Normal and Abnormal Frequency Ranges



Local Supplies of Reactive Power Are Essential to Maintaining Voltage Stability

A generator typically produces some mixture of "real" and "reactive" power, and the balance between them can be adjusted at short notice to meet changing conditions. Real power, measured in watts, is the form of electricity that powers equipment. Reactive power, a characteristic of AC systems, is measured in volt-amperes reactive (VAr), and is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps, and air conditioning.) Transmission lines both consume and produce reactive power. At light loads they are net producers, and at heavy loads, they are heavy consumers. Reactive power consumption by these facilities or devices tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances during heavy load conditions. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a "voltage collapse" may result.

flow must be limited to avoid overheating and damaging the equipment. In the case of overhead power lines, heating also causes the metal conductor to stretch or expand and sag closer to ground level. Conductor heating is also affected by ambient temperature, wind, and other factors. Flow on overhead lines must be limited to ensure that the line does not sag into obstructions below such as trees or telephone lines, or violate the minimum safety clearances between the energized lines and other objects. (A short circuit or "flashover"—which can start fires or damage equipment—can occur if an energized line gets too close to another object). Most transmission lines, transformers and other current-carrying devices are monitored continuously to ensure that they do not become overloaded or violate other operating constraints. Multiple ratings are typically used, one for normal conditions and a higher rating for emergencies. The primary means of limiting the flow of power on transmission lines is to adjust selectively the output of generators.

4. **Keep the system in a stable condition.** Because the electric system is interconnected and dynamic, electrical stability limits must be observed. Stability problems can develop very quickly—in just a few cycles (a cycle is 1/60th of a second)—or more slowly, over seconds or minutes. The main concern is to ensure that generation dispatch and the resulting power flows and voltages are such that the system is stable at all times. (As will be described later in this report, part of the Eastern Interconnection became unstable on August 14, resulting in a cascading outage over a wide area.) Stability limits, like thermal limits, are expressed as a maximum amount of electricity that can be safely transferred over transmission lines.

   There are two types of stability limits: (1) Voltage stability limits are set to ensure that the unplanned loss of a line or generator (which may have been providing locally critical reactive power support, as described previously) will not cause voltages to fall to dangerously low levels. If voltage falls too low, it begins to collapse uncontrollably, at which point automatic relays either shed load or trip generators to avoid damage. (2) Power (angle) stability limits are set to ensure that a short circuit or an unplanned loss of a line, transformer, or generator will not cause the remaining generators and loads being served to lose synchronism with one another. (Recall that all generators and loads within an interconnection must operate at or very near a common 60 Hz frequency.) Loss of synchronism with the common frequency means generators are operating out-of-step with one another. Even modest losses of synchronism can result in damage to generation equipment. Under extreme losses of synchronism, the grid may break apart into separate electrical islands; each island would begin to maintain its own frequency, determined by the load/generation balance within the island.

5. **Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N minus 1 criterion").** The central organizing principle of electricity reliability management is to plan for the unexpected. The unique characteristics of electricity

mean that problems, when they arise, can spread and escalate very quickly if proper safeguards are not in place. Accordingly, through years of experience, the industry has developed a network of defensive strategies for maintaining reliability based on the assumption that equipment can and will fail unexpectedly upon occasion.

This principle is expressed by the requirement that the system must be operated at all times to ensure that it will remain in a secure condition (generally within emergency ratings for current and voltage and within established stability limits) following the loss of the most important generator or transmission facility (a "worst single contingency"). This is called the "N-1 criterion." In other words, because a generator or line trip can occur at any time from random failure, the power system must be operated in a preventive mode so that the loss of the most important generator or transmission facility does not jeopardize the remaining facilities in the system by causing them to exceed their emergency ratings or stability limits, which could lead to a cascading outage.

Further, when a contingency does occur, the operators are required to identify and assess immediately the new worst contingencies, given the changed conditions, and promptly make any adjustments needed to ensure that if one of them were to occur, the system would still remain operational and safe. NERC operating policy requires that the system be restored as soon as practical but within no more than 30 minutes to compliance with normal limits, and to a condition where it can once again withstand the next-worst single contingency without violating thermal, voltage, or stability limits. A few areas of the grid are operated to withstand the concurrent loss of two or more facilities (i.e., "N-2"). This may be done, for example, as an added safety measure to protect

Why Don't More Blackouts Happen?

Given the complexity of the bulk power system and the day-to-day challenges of operating it, there are a lot of things that could go wrong—which makes it reasonable to wonder why so few large outages occur.

Large outages or blackouts are infrequent because responsible system owners and operators practice "defense in depth," meaning that they protect the bulk power system through layers of safety-related practices and equipment. These include:

1. **A range of rigorous planning and operating studies, including long-term assessments, year-ahead, season-ahead, week-ahead, day-ahead, hour-ahead, and real-time operational contingency analyses.** Planners and operators use these to evaluate the condition of the system, anticipate problems ranging from likely to low probability but high consequence, and develop a good understanding of the limits and rules for safe, secure operation under such contingencies. If multiple contingencies occur in a single area, they are likely to be interdependent rather than random, and should have been anticipated in planning studies.
2. **Preparation for the worst case.** The operating rule is to always prepare the system to be safe in the face of the worst single contingency that could occur relative to current conditions, which means that the system is also prepared for less adverse contingencies.
3. **Quick response capability.** Most potential problems first emerge as a small, local situation. When a small, local problem is handled quickly and responsibly using NERC operating practices—particularly to return the system to N-1 readiness within 30 minutes or less—the problem can usually be resolved and contained before it grows beyond local proportions.
4. **Maintain a surplus of generation and transmission.** This provides a cushion in day-to-day operations, and helps ensure that small problems don't become big problems.
5. **Have backup capabilities for all critical functions.** Most owners and operators maintain backup capabilities—such as redundant equipment already on-line (from generation in spinning reserve and transmission operating margin and limits to computers and other operational control systems)—and keep an inventory of spare parts to be able to handle an equipment failure.

a densely populated metropolitan area or when lines share a common structure and could be affected by a common failure mode, e.g., a single lightning strike.

6. **Plan, design, and maintain the system to operate reliably.** Reliable power system operation requires far more than monitoring and controlling the system in real-time. Thorough planning, design, maintenance, and analysis are required to ensure that the system can be operated reliably and within safe limits. Short-term planning addresses day-ahead and week-ahead operations planning; long-term planning focuses on providing adequate generation resources and transmission capacity to ensure that in the future the system will be able to withstand severe contingencies without experiencing widespread, uncontrolled cascading outages.

   A utility that serves retail customers must estimate future loads and, in some cases, arrange for adequate sources of supplies and plan adequate transmission and distribution infrastructure. NERC planning standards identify a range of possible contingencies and set corresponding expectations for system performance under several categories of possible events, ranging from everyday "probable" events to "extreme" events that may involve substantial loss of customer load and generation in a widespread area. NERC planning standards also address requirements for voltage support and reactive power, disturbance monitoring, facility ratings, system modeling and data requirements, system protection and control, and system restoration.

7. **Prepare for emergencies.** System operators are required to take the steps described above to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios. Operators must be trained to recognize and take effective action in response to these emergencies. To deal with a system emergency that results in a blackout, such as the one that occurred on August 14, 2003, there must be procedures and capabilities to use "black start" generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition.

Reliability Organizations Oversee Grid Reliability in North America

NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. The organization was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure compliance with reliability requirements. An independent board governs NERC.

To fulfill its mission, NERC:

- Sets standards for the reliable operation and planning of the bulk electric system.
- Monitors and assesses compliance with standards for bulk electric system reliability.
- Provides education and training resources to promote bulk electric system reliability.
- Assesses, analyzes and reports on bulk electric system adequacy and performance.
- Coordinates with regional reliability councils and other organizations.
- Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- Certifies reliability service organizations and personnel.
- Coordinates critical infrastructure protection of the bulk electric system.
- Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

Recent changes in the electricity industry have altered many of the traditional mechanisms, incentives and responsibilities of the entities involved in ensuring reliability, to the point that the voluntary system of compliance with reliability standards is generally recognized as not adequate to current needs.[3] NERC and many other electricity organizations support the development of a new mandatory system of reliability standards and compliance, backstopped in the United States by the Federal Energy Regulatory Commission. This will require federal legislation in the United States to provide for the creation of a new electric reliability organization with the statutory authority to enforce compliance with reliability standards among all market participants. Appropriate government entities in Canada and Mexico are prepared to take similar action, and some have already done so. In the meantime, NERC encourages compliance with its reliability standards through an agreement with its members.

NERC's members are ten regional reliability councils. (See Figure 2.5 for a map showing the locations and boundaries of the regional councils.) In turn, the regional councils have broadened their membership to include all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions. The August 14 blackout affected three NERC regional reliability councils—East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Northeast Power Coordinating Council (NPCC).

"Control areas" are the primary operational entities that are subject to NERC and regional council standards for reliability. A control area is a geographic area within which a single entity, Independent System Operator (ISO), or Regional Transmission Organization (RTO) balances generation and loads in real time to maintain reliable operation. Control areas are linked with each other through transmission interconnection tie lines. Control area operators control generation directly to maintain their electricity interchange schedules with other control areas. They also operate collectively to support the reliability of their interconnection. As shown in Figure 2.6, there are approximately 140 control areas in North America. The control area dispatch centers have sophisticated monitoring and control systems and are staffed 24 hours per day, 365 days per year.

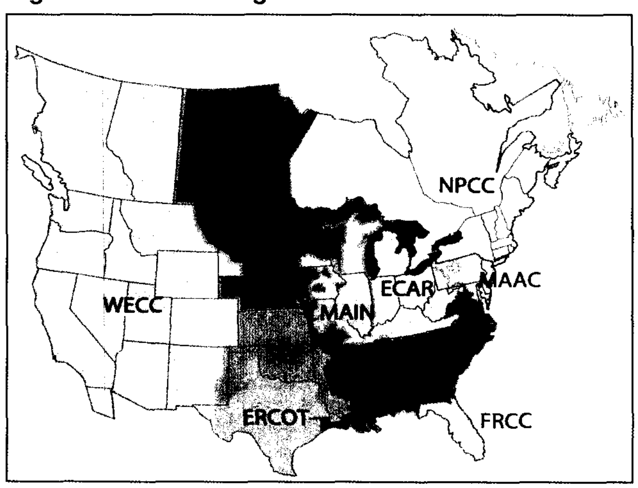
Traditionally, control areas were defined by utility service area boundaries and operations were largely managed by vertically integrated utilities that owned and operated generation, transmission, and distribution. While that is still true in some areas, there has been significant restructuring of operating functions and some consolidation of control areas into regional operating entities. Utility industry restructuring has led to an unbundling of generation, transmission and distribution activities such that the ownership and operation of these assets have been separated either functionally or through the formation of independent entities called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

- ISOs and RTOs in the United States have been authorized by FERC to implement aspects of the Energy Policy Act of 1992 and subsequent FERC policy directives.
- The primary functions of ISOs and RTOs are to manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets within their footprint.
- ISOs and RTOs do not own transmission assets; they operate or direct the operation of assets owned by their members.
- ISOs and RTOs may be control areas themselves, or they may encompass more than one control area.
- ISOs and RTOs may also be NERC Reliability Coordinators, as described below.

Five RTOs/ISOs are within the area directly affected by the August 14 blackout. They are:

- Midwest Independent System Operator (MISO)
- PJM Interconnection (PJM)

Figure 2.5. NERC Regions



◆ New York Independent System Operator (NYISO)

◆ New England Independent System Operator (ISO-NE)

◆ Ontario Independent Market Operator (IMO)

Reliability coordinators provide reliability oversight over a wide region. They prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They may operate, but do not participate in, wholesale or retail market functions. There are currently 18 reliability coordinators in North America. Figure 2.7 shows the locations and boundaries of their respective areas.

Key Parties in the Pre-Cascade Phase of the August 14 Blackout

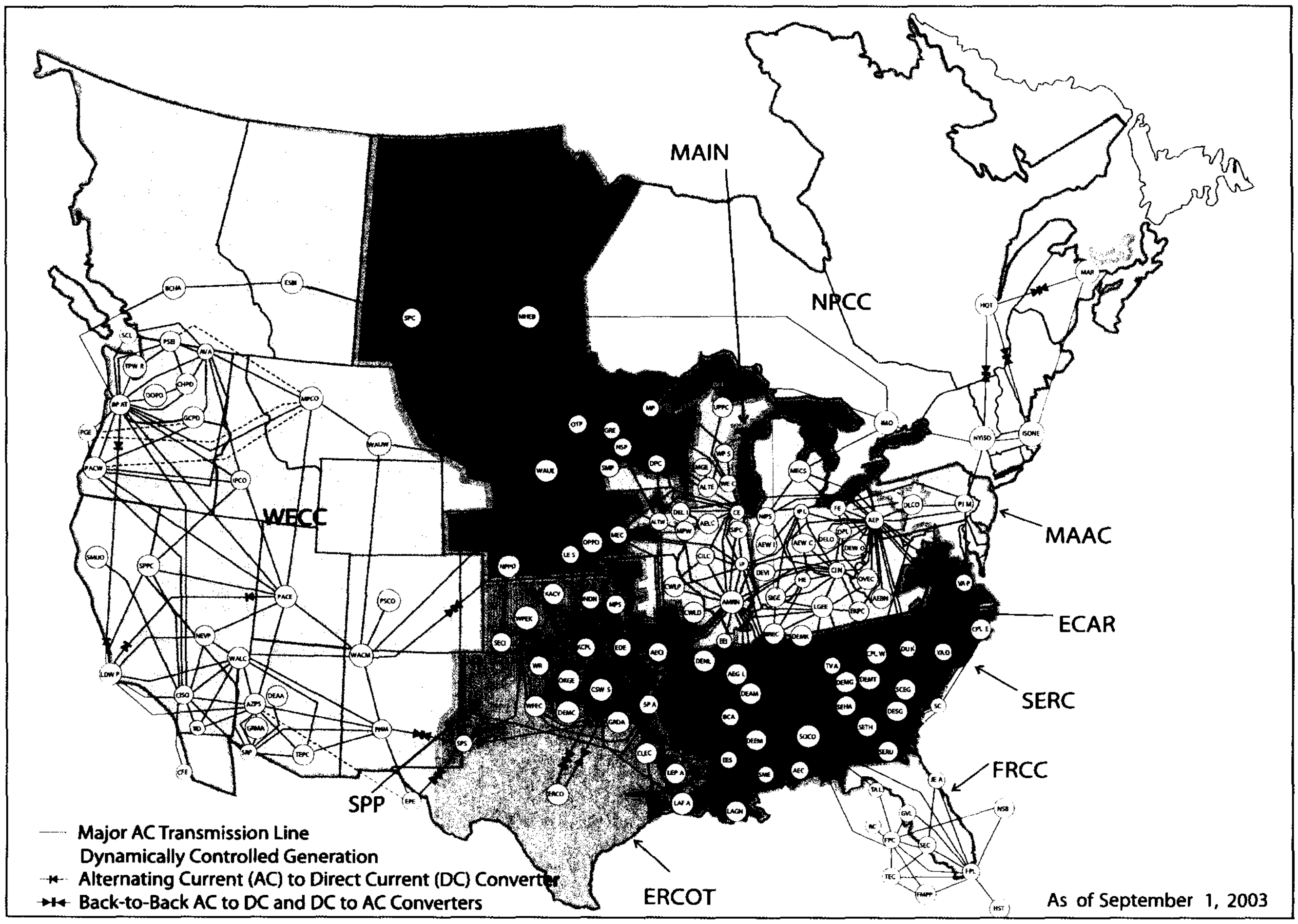
The initiating events of the blackout involved two control areas—FirstEnergy (FE) and American Electric Power (AEP)—and their respective reliability coordinators, MISO and PJM (see Figures 2.7 and 2.8). These organizations and their reliability responsibilities are described briefly in this final subsection.

1. **FirstEnergy operates a control area in northern Ohio.** FirstEnergy (FE) consists of seven electric utility operating companies. Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the NERC ECAR region, with MISO serving as their reliability coordinator. These four companies now operate as one integrated control area managed by FE.[4]

2. **American Electric Power (AEP) operates a control area in Ohio just south of FE.** AEP is both a transmission operator and a control area operator.

3. **Midwest Independent System Operator (MISO) is the reliability coordinator for FirstEnergy.** The Midwest Independent System

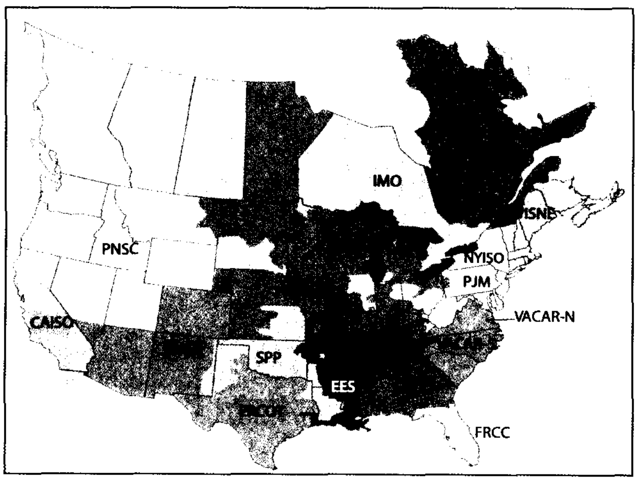
Figure 2.6. NERC Regions and Control Areas



Operator (MISO) is the reliability coordinator for a region of more than 1 million square miles (2.6 million square kilometers), stretching from Manitoba, Canada in the north to Kentucky in the south, from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Indiana. Overall, MISO provides reliability coordination for 37 control areas, most of which are members of MISO.

4. **PJM is AEP's reliability coordinator.** PJM is one of the original ISOs formed after FERC orders 888 and 889, but was established as a regional power pool in 1935. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR (PJM-West). It performs its duties as a reliability coordinator in different ways, depending on the control areas involved. For PJM-East, it is both the control area and reliability coordinator for ten utilities, whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. The PJM-West facility has the reliability coordinator desk for five control areas (AEP, Commonwealth Edison, Duquesne Light, Dayton Power and Light, and Ohio Valley Electric Cooperative) and three generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, and Allegheny Energy's Buchanan (West Virginia) facility.

Figure 2.7. NERC Reliability Coordinators



Reliability Responsibilities of Control Area Operators and Reliability Coordinators

1. **Control area operators have primary responsibility for reliability.** Their most important responsibilities, in the context of this report, are:

   N-1 criterion. NERC Operating Policy 2.A—Transmission Operations:

   > "All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

   Emergency preparedness and emergency response. NERC Operating Policy 5—Emergency Operations, General Criteria:

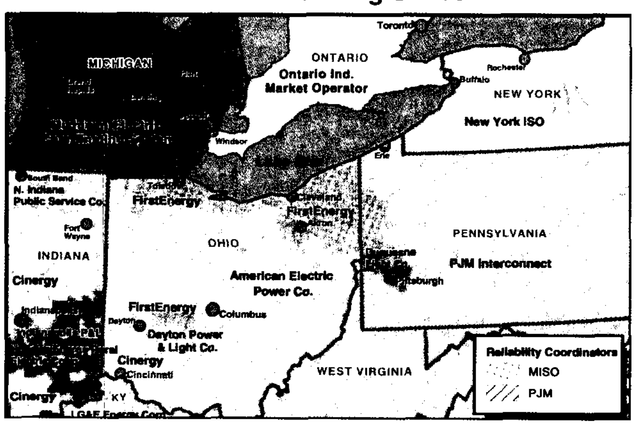
   > "Each system and CONTROL AREA shall promptly take appropriate action to relieve any abnormal conditions, which jeopardize reliable Interconnection operation."

   > "Each system, CONTROL AREA, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of the interconnection."

   NERC Operating Policy 5.A—Coordination with Other Systems:

   > "A system, CONTROL AREA, or pool that is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, CONTROL AREAS, or pools and throughout the interconnection . . . . A system shall inform

Figure 2.8. Reliability Coordinators and Control Areas in Ohio and Surrounding States



other systems . . . whenever . . . the system's condition is burdening other systems or reducing the reliability of the Interconnection . . . [or whenever] the system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection."

NERC Operating Policy 5.C—Transmission System Relief:

"Action to correct an OPERATING SECURITY LIMIT violation shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction."

Operating personnel and training: NERC Operating Policy 8.B—Training:

"Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies."

2. **Reliability Coordinators** such as MISO and PJM are expected to comply with all aspects of NERC Operating Policies, especially Policy 9, Reliability Coordinator Procedures, and its appendices. Key requirements include:

NERC Operating Policy 9, Criteria for Reliability Coordinators, 5.2:

Have "detailed monitoring capability of the RELIABILITY AREA and sufficient monitoring

Institutional Complexities and Reliability in the Midwest

The institutional arrangements for reliability in the Midwest are much more complex than they are in the Northeast—i.e., the areas covered by the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Council (MAAC). There are two principal reasons for this complexity. One is that in NPCC and MAAC, the independent system operator (ISO) also serves as the single control area operator for the individual member systems. In comparison, MISO provides reliability coordination for 35 control areas in the ECAR, MAIN, and MAPP regions and 2 others in the SPP region, and PJM provides reliability coordination for 8 control areas in the ECAR and MAIN regions (plus one in MAAC). (See table below.) This results in 18 control-area-to-control-area interfaces across the PJM/MISO reliability coordinator boundary.

The other is that MISO has less reliability-related authority over its control area members than PJM has over its members. Arguably, this lack of authority makes day-to-day reliability operations more challenging. Note, however, that (1) FERC's authority to require that MISO have greater authority over its members is limited; and (2) before approving MISO, FERC asked NERC for a formal assessment of whether reliability could be maintained under the arrangements proposed by MISO and PJM. After reviewing proposed plans for reliability coordination within and between PJM and MISO, NERC replied affirmatively but provisionally. FERC approved the new MISO-PJM configuration based on NERC's assessment. NERC conducted audits in November and December 2002 of the MISO and PJM reliability plans, and some of the recommendations of the audit teams are still being addressed. The adequacy of the plans and whether the plans were being implemented as written are factors in NERC's ongoing investigation.

Reliability Coordinator (RC)	Control Areas in RC Area	Regional Reliability Councils Affected and Number of Control Areas	Control Areas of Interest in RC Area
MISO	37	ECAR (12), MAIN (9), MAPP (14), SPP (2)	FE, Cinergy, Michigan Electric Coordinated System
PJM	9	MAAC (1), ECAR (7), MAIN (1)	PJM, AEP, Dayton Power & Light
ISO New England	2	NPCC (2)	ISONE, Maritime Provinces
New York ISO	1	NPCC (1)	NYISO
Ontario Independent Market Operator	1	NPCC (1)	IMO
Trans-Energie	1	NPCC (1)	Hydro Québec

capability of the surrounding RELIABILITY AREAS to ensure potential security violations are identified."

NERC Operating Policy 9, Functions of Reliability Coordinators, 1.7:

> "Monitor the parameters that may have significant impacts within the RELIABILITY AREA and with neighboring RELIABILITY AREAS with respect to . . . sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY AREAS. The RELIABILITY COORDINATOR will coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS as needed to develop appropriate plans to mitigate negative impacts of potential, expected, or actual critical operating conditions . . . ."

What Constitutes an Operating Emergency?

An operating emergency is an unsustainable condition that cannot be resolved using the resources normally available. The NERC Operating Manual defines a "capacity emergency" as when a system's or pool's operating generation capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements. It defines an "energy emergency" as when a load-serving entity has exhausted all other options and can no longer provide its customers' expected energy requirements. A transmission emergency exists when "the system's line loadings and voltage/ reactive levels are such that a single contingency could threaten the reliability of the Interconnection." Control room operators and dispatchers are given substantial latitude to determine when to declare an emergency. (See pages 66-67 in Chapter 5 for more detail.)

NERC Operating Policy 9, Functions of Reliability Coordinators, 6:

> "Conduct security assessment and monitoring programs to assess contingency situations. Assessments shall be made in real time and for the operations planning horizon at the CONTROL AREA level with any identified problems reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that CONTROL AREA, RELIABILITY AREA, and regional boundaries are sufficiently modeled to capture any problems crossing such boundaries."

Endnotes

1 The province of Québec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection only by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

2 In some locations, bulk power flows are controlled through specialized devices or systems, such as phase angle regulators, "flexible AC transmission systems" (FACTS), and high-voltage DC converters (and reconverters) spliced into the AC system. These devices are still too expensive for general application.

3 See, for example, *Maintaining Reliability in a Competitive Electric Industry* (1998), a report to the U.S. Secretary of Energy by the Task Force on Electric Systems Reliability; *National Energy Policy* (2001), a report to the President of the United States by the National Energy Policy Development Group, p. 7-6; and *National Transmission Grid Study* (2002), U.S. Dept. of Energy, pp. 46-48.

4 The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the NERC MAAC region and have PJM as their reliability coordinator. The focus of this report is on the portion of FE in the ECAR reliability region and within the MISO reliability coordinator footprint.

Brief Description System performance under normal (no contingency) conditions.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

Measure

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S1.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category A of Table 1 (no contingencies) that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category A.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

2. Be conducted annually unless changes to system conditions do not warrant such analyses.
3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
4. Have established normal (pre-contingency) operating procedures in place.
5. Have all projected firm transfers modeled.
6. Be performed for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon:
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

System performance under normal (no contingency) conditions.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions*

Category	Contingencies: Initiating Event(s) and Contingency Element(s)	Elements Out of Service	System Limits or Impacts: Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages[c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No

* Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

NERC Planning Standards

Brief Description System performance following loss of a single bulk system element.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

Measure

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S2.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category B contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category B,
5. Consider all contingencies applicable to Category B.

System Simulation Study/Testing Methods

System simulation studies/testing shall:

1. Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category B contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M2), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of a single bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Council. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions*

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages[c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled[d] Planned/Controlled[d]	 No No

* Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section --- 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) --- Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description System performance following loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers maybe necessary to meet this standard.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category C of Table I (attached).

Measure

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 contingencies are as defined in Category C (event(s) resulting in the loss of two or more (multiple) elements element of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs).

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S3.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons,
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category C contingencies that addresses the plan year being assessed,
4. Address any planned upgrades needed to meet the performance requirements of Category C,

5. Consider all contingencies applicable to Category C.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agreed to by the Region):

1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts.
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
5. Have all projected firm transfers modeled.
6. Be performed and evaluated for selected demand levels over the range of forecast system demands.
7. Demonstrate that system performance meets Table 1 for Category C contingencies.
8. Include existing and planned facilities.
9. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
11. Include the effects of existing and planned control devices.
12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

When system simulations indicate an inability of the systems to respond as prescribed in this Measure (M3), responsible entities shall:

1. Provide a written summary of their plans to achieve the required system performance as described above throughout the planning horizon,
   a. Including a schedule for implementation,
   b. Including a discussion of expected required in-service dates of facilities,
   c. Consider lead times necessary to implement plans.
2. For identified system facilities for which sufficient lead times exist, review in subsequent annual assessments for continuing need — detailed implementation plans are not needed.

Reporting Requirements

The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a report of its reliability assessments and corrective actions to NERC.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments supported by simulated system performance following loss of two or more bulk system element.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — N/A

Level 2 — A valid assessment and corrective plan, as defined above, for the longer-term planning horizon is not available.

Level 3 — N/A

Level 4 — A valid assessment and corrective plan, as defined above, for the near-term planning horizon is not available.

Compliance Monitoring Responsibility

Regional Reliability Councils

Table I. Transmission Systems Standards — Normal and Contingency Conditions*

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Single Single Single Single	A/R A/R A/R A/R	A/R A/R A/R A/R	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

* Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D[e] - Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[f]: 5. Breaker (failure or internal fault) - Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading *is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained* from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing *is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.* Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Brief Description System performance following extreme events resulting in the loss of two or more bulk system elements.

Category Assessments

Section I. System Adequacy and Security
A. Transmission Systems

Standard

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

Measure

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements

Entities Responsible for the Reliability of Interconnected transmission Systems (ERRIS), as determined by the Region, for example:

1. Transmission owners,
2. Independent system operators (ISOs),
3. Regional transmission organizations (RTOs),

Or other groups responsible for planning the bulk electric system shall assess the performance of their systems in meeting Standard S4.

To be valid *and compliant*, assessments shall:

1. Be made annually,
2. Be conducted for near-term (years one through five),
3. Be supported by a current or past study and/or system simulation testing as accepted by the Region showing system performance following Category D contingencies that addresses the plan year being assessed,
4. Consider all contingencies applicable to Category D.

System Simulation Study/Testing Methods

System simulation studies/testing shall (as agree to by the Region):

1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts:
   a. The rationale for the contingencies selected for evaluation shall be available as supporting information,
   b. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
3. Be conducted annually unless changes to system conditions do not warrant such analyses.
4. Have all projected firm transfers modeled.
5. Include existing and planned facilities.
6. Include reactive power resources to ensure that adequate reactive resources are available to meet system performance.
7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
8. Include the effects of existing and planned control devices.
9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Corrective Plan Requirements

None required.

Reporting Requirements

The documentation of results of these reliability assessments shall annually be provided to the entities' respective NERC Region(s), as required by the Region.

Applicable to

Entities responsible for reliability of interconnected transmission systems.

Items to be Measured

Assessments of system performance for extreme events (more severe than in I.A.M3) resulting in loss of two or more bulk system elements.

Timeframe

Annually

Levels of Non-Compliance (If non-compliant at more than one Level, the highest Level applies.)

Level 1 — A valid assessment, as defined above, for the near-term planning horizon is not available.

Level 2 — N/A

Level 3 — N/A

Level 4 — N/A

Compliance Monitoring Responsibility

Regional Reliability Councils. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Table I. Transmission Systems Standards — Normal and Contingency Conditions*

Category	Contingencies: Initiating Event(s) and Contingency Element(s)	Elements Out of Service	System Limits or Impacts: Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading Outages [c]
A - No Contingencies	All Facilities in Service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B - Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Single Single Single Single	 A/R A/R A/R A/R	 A/R A/R A/R A/R	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No [b]	No
C - Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [f]: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled [d] Planned/Controlled [d]	 No No
	SLG or 3Ø Fault, with Normal Clearing [f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled [d]	No
	Bipolar Block, with Normal Clearing [f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [f]: 5. Any two circuits of a multiple circuit towerline [g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled [d] Planned/Controlled [d]	No No
	SLG Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned/Controlled [d] Planned/Controlled [d]	 No No

* Any Region may implement standards that are more stringent, but not inconsistent with NERC's industry-wide standards.

D [e] - Extreme event resulting in two or more *(multiple)* elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant *special protection system (or remedial action scheme)* in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared *in the time normally expected with proper functioning of the installed protection systems.* Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

APPENDIX C

RESULTS SUMMARY

Scenario	# Cat B Contingencies	"Raw" Results	Caused by X Contingencies	Significant Results*	Caused by X Contingencies	Cascade Results >500 MW	Cascade Results No Load	Cascade Results Interrupted	Cascade Results Total
Base Case	769	74	21	50	15	Not run through Cascade Analysis Tool			
Import	767	60	34	38	17	0	0	0	0
SN	767	163	75	93	44	1	3	0	4 **
NS	767	448	105	231	63	2	3	0	5 **

Scenario	# Cat C Contingencies	"Raw" Results	Caused by X Contingencies	Significant Results*	Caused by X Contingencies	Cascade Results >500 MW	Cascade Results No Load	Cascade Results Interrupted	Cascade Results Total	Roll Up Total	Roll Up Potential Cascade
Base Case	23,890	3,611	1,635	1,381	674***	61	36	27	124	157	83
Bus Fault	380	129	44	112	37	5	2	3	10	NA	NA
Breaker Failure	43	24	18	19	17	2	0	0	2	NA	NA
Import	23,533	5,266	3,256	1,891	836***	84	62	12	158	179	90
SN	22,109	15,299	7,234	3,714	1,979	76	174	76	326	178	65
NS	27,178	25,024	9,824	8,506	3,154	160	241	50	451	228	113

*Significant Results were identified for subsequent analysis by the Cascade Analysis Tool. A contingency was deemd significant if it caused *overloads* >105% *on any facility* or *voltages* <0.90pu at any bus. Contingenices causing only voltage change violations (>0.1 pu) were not checked for further cascading potential.

**We were able to find operating procedures to eliminate violations associated with all of the contingencies *identified as having the potential* to cascade using the 105% overload and 0.9 pu voltage criteria.

****these counts of significant contingencies for the base and import cases are 809 and 917, respectively if the contingencies causing only voltage change 'violations' are included. Since this criterion was not used to determine the list that *would be run through the cascade tool*, these contigencies have been removed from the 809 and 917 numbers.

Scenario	# Cat D Contingencies	"Raw" Results	Caused by X Contingencies	Significant Results****	Caused by X Contingencies
Base Case	5,771	4,048	636	1,114	188

****This number and the 188 contingencies that caused these significant results include 7 contingencies that diverged.

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