

4. Context and Preconditions for the Blackout: The Northeastern Power Grid Before the Blackout Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days and hours before 16:00 EDT on August 14, 2003, to determine whether grid conditions before the blackout were in some way unusual and might have contributed to the initiation of the blackout. Task Force investigators found that at 15:05 Eastern Daylight Time, immediately before the tripping (automatic shutdown) of FirstEnergy’s (FE) Harding-Chamberlin 345-kV transmission line, the system was electrically secure and was able to withstand the occurrence of any one of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that time the system was electrically within prescribed limits and in compliance with NERC’s operating policies.

Determining that the system was in a reliable operational state at 15:05 EDT on August 14, 2003, is extremely significant for determining the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a direct cause of the blackout. This eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as:

- ◆ Unavailability of individual generators or transmission lines
- ◆ High power flows across the region
- ◆ Low voltages earlier in the day or on prior days
- ◆ System frequency variations
- ◆ Low reactive power output from independent power producers (IPPs).

This chapter documents that although the system was electrically secure, there was clear experience and evidence that the Cleveland-Akron area was highly vulnerable to voltage instability problems. While it was possible to operate the system

securely despite those vulnerabilities, FirstEnergy was not doing so because the company had not conducted the long-term and operational planning studies needed to understand those vulnerabilities and their operational implications.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 does not change the responsibilities and actions expected of the organizations and operators charged with ensuring power system reliability. As described in Chapter 2, the electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared for the unexpected. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways and at

Reliability and Security

NERC—and this report—use the following definitions for reliability, adequacy, and security.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electricity supply.

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

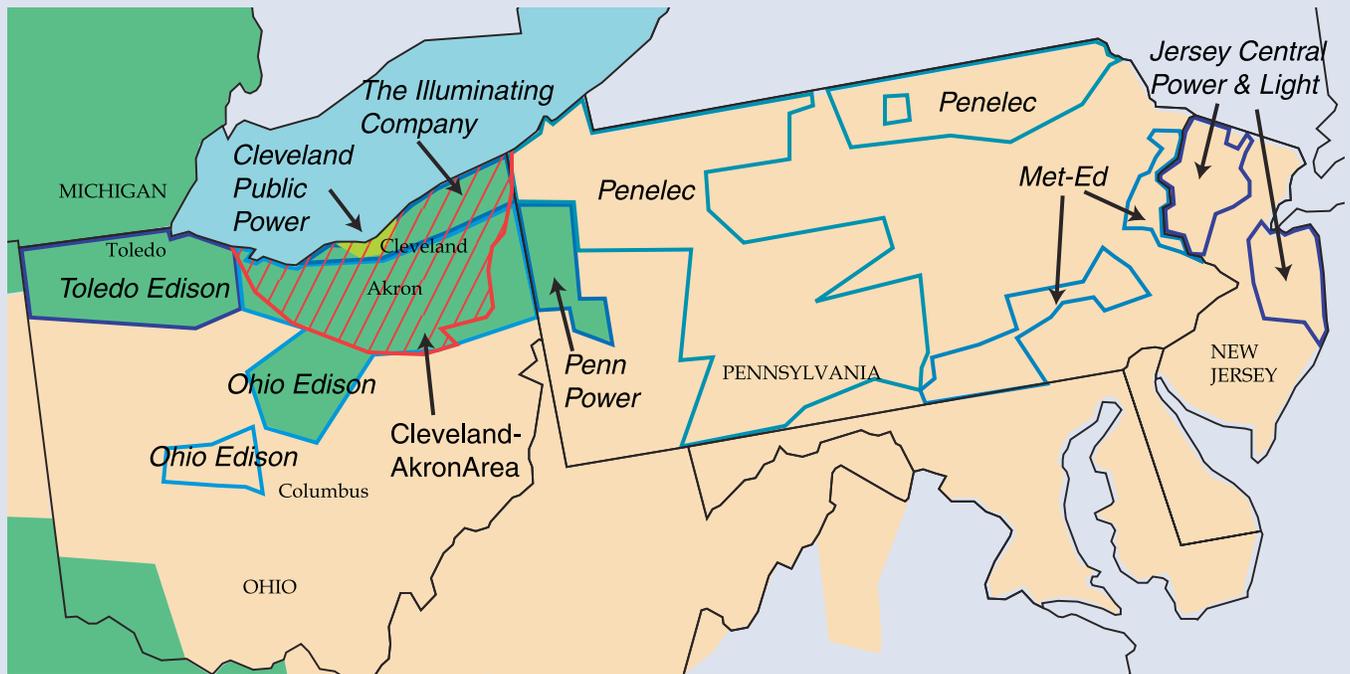
unpredictable times. Sound reliability management is designed to ensure that operators can continue to operate the system within appropriate thermal, voltage, and stability limits following the unexpected loss of any key element (such as a major generator or key transmission facility). These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal.

It is a basic principle of reliability management that “operators must operate the system they have in front of them”—unconditionally. The system must be operated at all times to withstand any single contingency and yet be ready within 30 minutes for the next contingency. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes, including adjusting generator outputs, curtailing

Geography Lesson

In analyzing the August 14 blackout, it is crucial to understand the geography of the FirstEnergy area. FirstEnergy has seven subsidiary distribution utilities: Toledo Edison, Ohio Edison, and The Illuminating Company in Ohio and four more in Pennsylvania and New Jersey. Its Ohio control area spans the three Ohio distribution utility footprints and that of Cleveland Public Power, a municipal utility serving the city of Cleveland. Within FE’s Ohio control area is the Cleveland-Akron area, shown in red cross-hatch.

This geographic distinction matters because the Cleveland-Akron area is a transmission-constrained load pocket with relatively limited generation. While some analyses of the blackout refer to voltages and other indicators measured at the boundaries of FE’s Ohio control area, those indicators have limited relevance to the blackout—the indicators of conditions at the edges of and within the Cleveland-Akron area are the ones that matter.



Area	All-Time Peak Load (MW)	Load on August 14, 2003 (MW)
Cleveland-Akron Area (including Cleveland Public Power)	7,340	6,715
FirstEnergy Control Area, Ohio	13,299	12,165
FirstEnergy Retail Area, including PJM	24,267	22,631

NA = not applicable.

electricity transactions, taking transmission elements out of service or restoring them, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

This chapter discusses system conditions in and around northeast Ohio on August 14 and their relevance to the blackout. It reviews electric loads (real and reactive), system topology (transmission and generation equipment availability and capabilities), power flows, voltage profiles and reactive power reserves. The discussion examines actual system data, investigation team modeling results, and past FE and AEP experiences in the Cleveland-Akron area. The detailed analyses will be presented in a NERC technical report.

Electric Demands on August 14

Temperatures on August 14 were hot but in a normal range throughout the northeast region of the United States and in eastern Canada (Figure 4.1). Electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. As the temperature increased from 78°F (26°C) on August 11 to 87°F (31°C) on August 14, peak load within FirstEnergy’s control area increased by 20%, from 10,095 MW to 12,165 MW. System operators had successfully managed higher demands in northeast Ohio and across the Midwest, both earlier in the summer and in previous years—historic peak load for FE’s control area was 13,299 MW. August 14 was FE’s peak demand day in 2003.

Several large operators in the Midwest consistently under-forecasted load levels between

August 11 and 14. Figure 4.2 shows forecast and actual power demands for AEP, Michigan Electrical Coordinated Systems (MECS), and FE from August 11 through August 14. Variances between actual and forecast loads are not unusual, but because those forecasts are used for day-ahead planning for generation, purchases, and reactive power management, they can affect equipment availability and schedules for the following day.

The existence of high air conditioning loads across the Midwest on August 14 is relevant because air conditioning loads (like other induction motors) have lower power factors than other customer electricity uses, and consume more reactive power. Because it had been hot for several days in the Cleveland-Akron area, more air conditioners were running to overcome the persistent heat, and consuming relatively high levels of reactive power—further straining the area’s limited reactive generation capabilities.

Generation Facilities Unavailable on August 14

Several key generators in the region were out of service going into the day of August 14. On any given day, some generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and require repairs. August 14, 2003, in northeast Ohio was no exception (Table 4.1).

The generating units that were not available on August 14 provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under standard practice, system operators take into account the unavailability of such units and any

Figure 4.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada

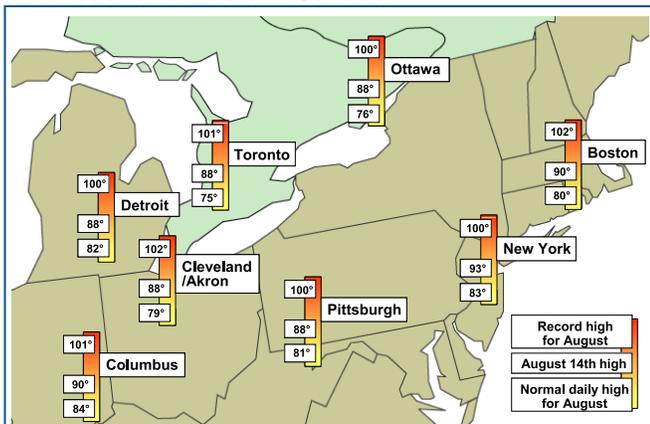
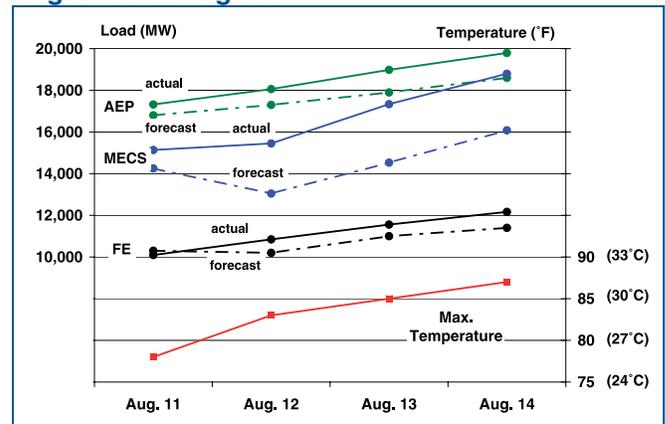


Figure 4.2. Load Forecasts Below Actuals, August 11 through 14



transmission facilities known to be out of service in the day-ahead planning studies they perform to ensure a secure system for the next day. Knowing the status of key facilities also helps operators determine in advance the safe electricity transfer levels for the coming day.

MISO’s day-ahead planning studies for August 14 took the above generator outages and transmission outages reported to MISO into account and

determined that the regional system could be operated safely. The unavailability of these generation units did not cause the blackout.

On August 14 four or five capacitor banks within the Cleveland-Akron area had been removed from service for routine inspection, including capacitor banks at Fox and Avon 138-kV substations.¹ These static reactive power sources are important for voltage support, but were not restored to

Table 4.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	883 MW	Prolonged NRC-ordered outage beginning on 3/22/02
Sammis Unit 3	180 MW	Forced outage on 8/12/03
Eastlake Unit 4	238 MW	Forced outage on 8/13/03
Monroe Unit 1	817 MW	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	Outage began on 8/13/03

Load Power Factors and Reactive Power

Load power factor is a measure of the relative magnitudes of real power and reactive power consumed by the load connected to a power system. Resistive load, such as electric space heaters or incandescent lights, consumes only real power and no reactive power and has a load power factor of 1.0. Induction motors, which are widely used in manufacturing processes, mining, and homes (e.g., air-conditioners, fan motors in forced-air furnaces, and washing machines) consume both real power and reactive power. Their load power factors are typically in the range of 0.7 to 0.9 during steady-state operation. Single-phase small induction motors (e.g., household items) generally have load power factors in the lower range.

The lower the load power factor, the more reactive power is consumed by the load. For example, a 100 MW load with a load power factor of 0.92 consumes 43 MVar of reactive power, while the same 100 MW of load with a load power factor of 0.88 consumes 54 MVar of reactive power. Under depressed voltage conditions, the induction motors used in air-conditioning units and refrigerators, which are used more heavily on hot and humid days, draw even more reactive power than under normal voltage conditions.

In addition to end-user loads, transmission elements such as transformers and transmission lines consume reactive power. Reactive power compensation is required at various locations in the network to support the transmission of real

power. Reactive power is consumed within transmission lines in proportion to the square of the electric current shipped, so a 10% increase of power transfer will require a 21% increase in reactive power generation to support the power transfer.

In metropolitan areas with summer peaking loads, it is generally recognized that as temperatures and humidity increase, load demand increases significantly. The power factor impact can be quite large—for example, for a metropolitan area of 5 million people, the shift from winter peak to summer peak demand can shift peak load from 9,200 MW in winter to 10,000 MW in summer; that change to summer electric loads can shift the load power factor from 0.92 in winter down to 0.88 in summer; and this will increase the MVar load demand from 3,950 in winter up to 5,400 in summer—all due to the changed composition of end uses and the load factor influences noted above.

Reactive power does not travel far, especially under heavy load conditions, and so must be generated close to its point of consumption. This is why urban load centers with summer peaking loads are generally more susceptible to voltage instability than those with winter peaking loads. Thus, control areas must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation.

service that afternoon despite the system operators' need for more reactive power in the area.² Normal utility practice is to inspect and maintain reactive resources in off-peak seasons so the facilities will be fully available to meet peak loads.

Cause 1
Inadequate System Understanding

The unavailability of the critical reactive resources was not known to those outside of FirstEnergy. NERC policy requires that critical facilities be identified and that neighboring control areas and reliability coordinators be made aware of the status of those facilities to identify the impact of those conditions on their own facilities. However, FE never identified these capacitor banks as critical and so did not pass on status information to others.

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Unanticipated Outages of Transmission and Generation on August 14

Three notable unplanned outages occurred in Ohio and Indiana on August 14 before 15:05 EDT. Around noon, several Cinergy transmission lines in south-central Indiana tripped; at 13:31 EDT, FE's Eastlake 5 generating unit along the southwestern shore of Lake Erie tripped; at 14:02 EDT, a line within the Dayton Power and Light (DPL) control area, the Stuart-Atlanta 345-kV line in southern Ohio, tripped. Only the Eastlake 5 trip was electrically significant to the FirstEnergy system.

- ◆ Transmission lines on the Cinergy 345-, 230-, and 138-kV systems experienced a series of outages starting at 12:08 EDT and remained out of service during the entire blackout. The loss of these lines caused significant voltage and loading problems in the Cinergy area. Cinergy made generation changes, and MISO operators responded by implementing transmission loading relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, pages 41-43) showed that the loss of these lines was not electrically related to subsequent events in northern Ohio that led to the blackout.
- ◆ The Stuart-Atlanta 345-kV line, operated by DPL, and monitored by the PJM reliability coordinator, tripped at 14:02 EDT. This was the result of a tree contact, and the line remained out of service the entire afternoon. As explained below, system modeling by the investigation

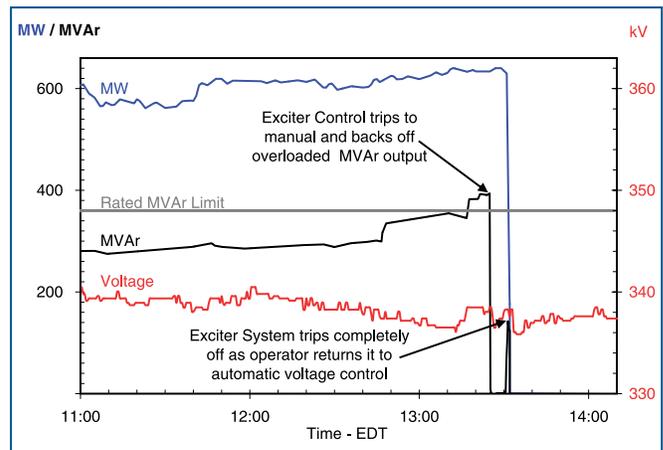
team has shown that this outage did not cause the subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line and did not know it had gone out of service. This led to a data mismatch that prevented MISO's state estimator (a key monitoring tool) from producing usable results later in the day at a time when system conditions in FE's control area were deteriorating (see details below, pages 46 and 48-49).

- ◆ Eastlake Unit 5 is a 597 MW (net) generating unit located west of Cleveland on Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31 EDT. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power output (Figure 4.3), the unit's protection system detected that VAR output exceeded the unit's VAR capability and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (612 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details on pages 45-46 and 49-50).

Key Parameters for the Cleveland-Akron Area at 15:05 EDT

The investigation team benchmarked their power flow models against measured data provided by

Figure 4.3. MW and MVar Output from Eastlake Unit 5 on August 14



FirstEnergy for the Cleveland-Akron area at 15:05 EDT (just before the first of FirstEnergy’s key transmission lines failed), as shown in Table 4.2. Although the modeled figures do not match actual system conditions perfectly, overall this model shows a very high correspondence to the actual occurrences and thus its results merit a high degree of confidence. Although Table 4.2 shows only a few key lines within the Cleveland-Akron area, the model was successfully benchmarked to match actual flows, line-by-line, very closely across the entire area for the afternoon of August 14, 2003.

The power flow model assumes the following system conditions for the Cleveland-Akron area at 15:05 EDT on August 14:

- ◆ Cleveland-Akron area load = 6,715 MW and 2,402 MVAR
- ◆ Transmission losses = 189 MW and 2,514 MVAR
- ◆ Reactive power from fixed shunt capacitors (all voltage levels) = 2,585 MVAR
- ◆ Reactive power from line charging (all voltage levels) = 739 MVAR
- ◆ Network configuration = after the loss of Eastlake 5, before the loss of Harding-Chamberlin 345-kV line
- ◆ Area generation combined output: 3,000 MW and 1,200 MVAR.

Cause 1
Inadequate System Understanding

Given these conditions, the power flow model indicates that about 3,900 MW and 400 MVAR of real power and reactive power flow into the Cleveland-Akron area was needed to meet the sum of customer load demanded plus line losses. There was about 688 MVAR of reactive reserve from generation in the area, which is slightly more than the 660 MVAR reactive capability of the Perry nuclear unit. Combined with the fact that a 5% reduction in operating voltage would cause a 10% reduction in

reactive power (330 MVAR) from shunt capacitors and line charging and a 10% increase (250 MVAR) in reactive losses from transmission lines, these parameters indicate that the Cleveland-Akron area would be precariously short of reactive power if the Perry plant were lost.

Power Flow Patterns

Several commentators have suggested that the voltage problems in northeast Ohio and the subsequent blackout occurred due to unprecedented high levels of inter-regional power transfers occurring on August 14. Investigation team analysis indicates that in fact, power transfer levels were high but were within established limits and previously experienced levels. Analysis of actual and test case power flows demonstrates that inter-regional power transfers had a minimal effect on the transmission corridor containing the Harding-Chamberlin, Hanna-Juniper, and Star-South Canton 345-kV lines on August 14. It was the increasing native load relative to the limited amount of reactive power available in the Cleveland-Akron area that caused the depletion of reactive power reserves and declining voltages.

On August 14, the flow of power through the ECAR region as a whole (lower Michigan, Indiana, Ohio, Kentucky, West Virginia, and western Pennsylvania) was heavy as a result of transfers of power from the south (Tennessee, etc.) and west (Wisconsin, Minnesota, Illinois, Missouri, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York, Pennsylvania). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario. This is shown in Figure 4.4, which shows the flows between control areas on August 14 based on power flow simulations just before the Harding-Chamberlin line tripped at 15:05 EDT. FE’s total load peaked at 12,165MW at 16:00 EDT. Actual system data indicate that between 15:00 and 16:00 EDT, actual line flows into FE’s control area were 2,695 MW for both transactions and native load.

Table 4.2. Benchmarking Model Results to Actual

FE Circuit		MVA Comparison		Benchmark Accuracy
From	To	Model Base Case MVA	Actual 8/14 MVA	
Chamberlin	Harding	482	500	3.6%
Hanna	Juniper	1,009	1,007	0.2%
S. Canton	Star	808	810	0.2%
Tidd	Canton Central	633	638	0.8%
Sammis	Star	728	748	2.7%

Figure 4.4. Generation, Demand, and Interregional Power Flows on August 14, 2003, at 15:05 EDT

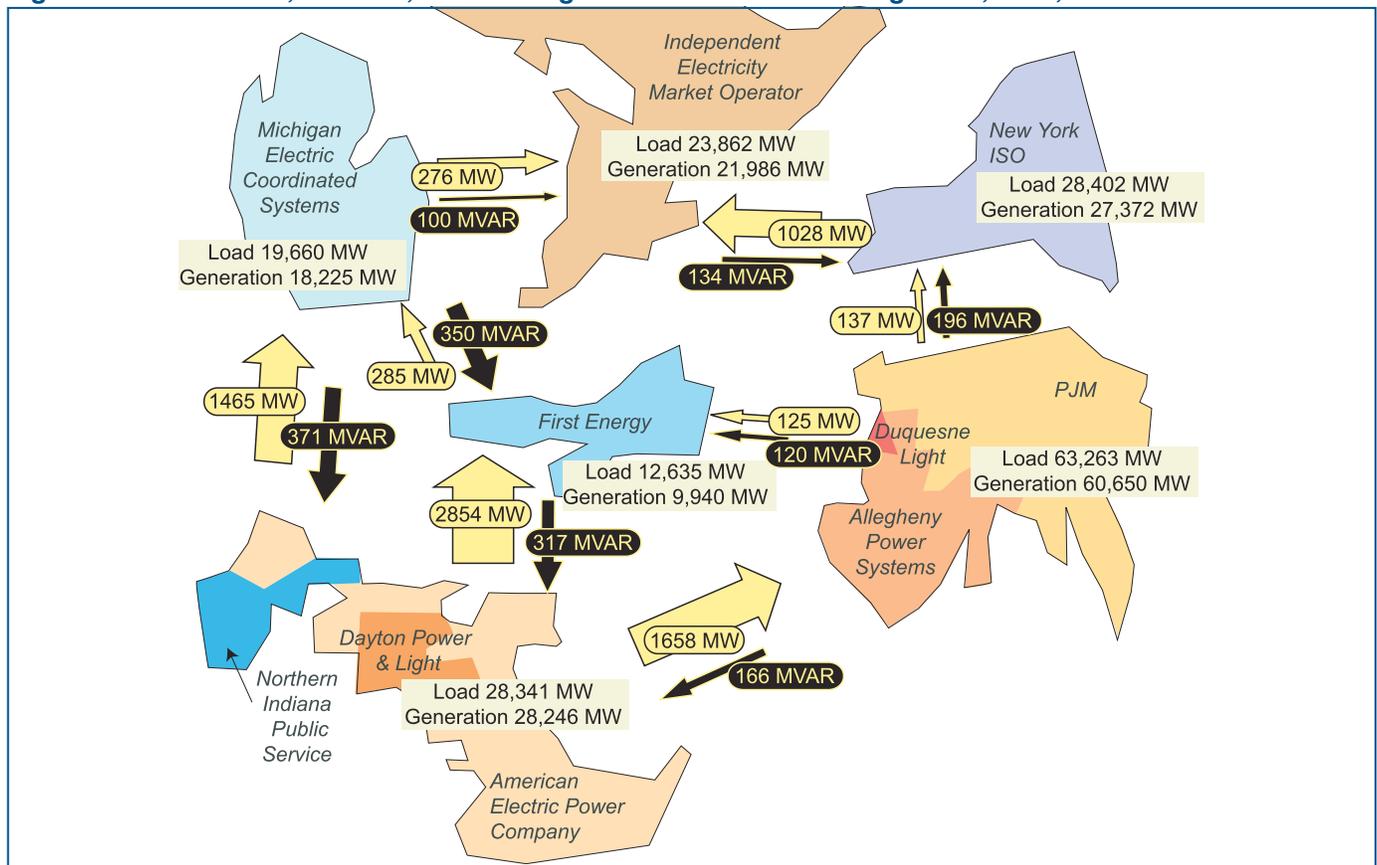
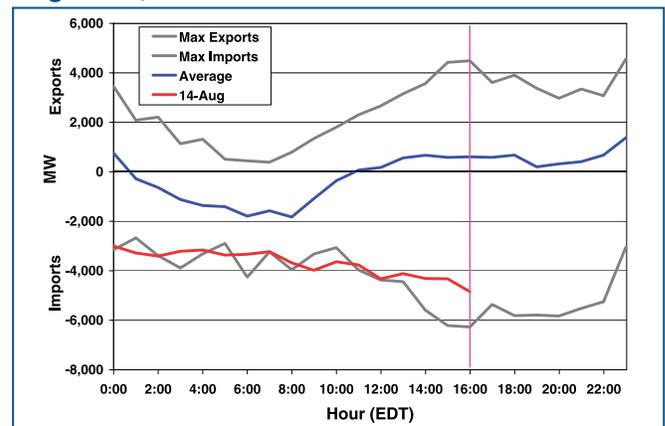


Figure 4.5 shows total scheduled imports for the entire northeast region for June through August 14, 2003. These transfers were well within the range of previous levels, as shown in Figure 4.5, and well within all established limits. In particular, on August 14 increasing amounts of the growing imports into the area were being delivered to FirstEnergy's Ohio territory to meet its increasing demand and to replace the generation lost with the trip of Eastlake 5. The level of imports into Ontario from the U.S. on August 14 was high (e.g., 1,334 MW at 16:00 EDT through the New York and Michigan ties) but not unusual, and well within IMO's import capability. Ontario is a frequent importer and exporter of power, and had imported similar and higher amounts of power several times during the summers of 2002 and 2003. PJM and Michigan also routinely import and export power across ECAR.

Some have suggested that the level of power flows into and across the Midwest was a direct cause of the blackout on August 14. Investigation team modeling proves that these flows were neither a cause nor a contributing factor to the blackout. The team used detailed modeling and simulation incorporating the NERC TagNet data on actual

Figure 4.5. Scheduled Imports and Exports for the Northeast Central Region, June 1 through August 13, 2003



Note: These flows from within the Northeast Central Area include ECAR, PJM, IMO, NYISO, and exclude transfers from Québec, the Maritimes and New England, since the latter areas had minimal flows across the region of interest.

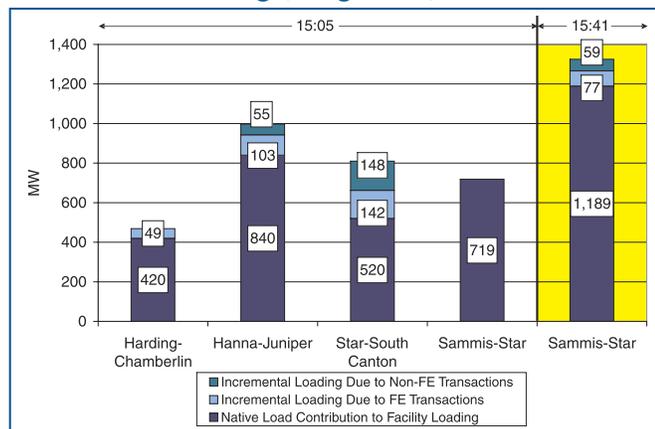
transactions to determine whether and how the transactions affected line loadings within the Cleveland-Akron area. The MUST (Managing Utilization of System Transmission) analytical tool uses the transactions data from TagNet along with a power flow program to determine the impact of transactions on the loading of transmission

flowgates or specific facilities, calculating transfer distribution factors across the various flowgates. The MUST analysis shows that for actual flows at 15:05 EDT, only 10% of the loading on Cleveland-Akron lines was for through flows for which FE was neither the importer nor exporter.

According to real-time TagNet records, at 15:05 EDT the incremental flows due to transactions were approximately 2,800 MW flowing into the FirstEnergy control area and approximately 800 MW out of FE to Duquesne Light Company (DLCO). Among the flows into or out of the FE control area, the bulk of the flows were for transactions where FE was the recipient or the source—at 15:05 EDT the incremental flows due to transactions into FE were 1,300 MW from interconnections with PJM, AEP, DPL and MECS, and approximately 800 MW from interconnections with DLCO. But not all of that energy moved through the Cleveland-Akron area and across the lines which failed on August 14, as Figure 4.6 shows.

Figure 4.6 shows how all of the transactions flowing across the Cleveland-Akron area on the afternoon of August 14 affected line loadings at key FE facilities, organized by time and types of transactions. It shows that before the first transmission line failed, the bulk of the loading on the four critical FirstEnergy circuits—Harding-Chamberlin, Hanna-Juniper, Star-South Canton and Sammis-Star—was to serve Cleveland-Akron area native load. Flows to serve native load included transfers from FE’s 1,640 MW Beaver Valley nuclear power plant and its Seneca plant, both in Pennsylvania, which have been traditionally counted by FirstEnergy not as imports but rather as in-area

Figure 4.6. Impacts of Transactions Flows on Critical Line Loadings, August 14, 2003



generation, and as such excluded from TLR curtailments. An additional small increment of line loading served transactions for which FE was either the importer or exporter, and the remaining line loading was due to through-flows initiated and received by other entities. The Star-South Canton line experienced the greatest impact from through-flows—148 MW, or 18% of the total line loading at 15:05 EDT, was due to through-flows resulting from non-FE transactions. By 15:41 EDT, right before Star-South Canton tripped—without being overloaded—the Sammis-Star line was serving almost entirely native load, with loading from through-flows down to only 4.5%.

Cause 1
Inadequate System Understanding

The central point of this analysis is that because the critical lines were loaded primarily to serve native load and FE-related flows, attempts to reduce flows through

transaction curtailments in and around the Cleveland-Akron area would have had minimal impact on line loadings and the declining voltage situation within that area. Rising load in the Cleveland-Akron area that afternoon was depleting the remaining reactive power reserves. Since there was no additional in-area generation, only in-area load cuts could have reduced local line loadings and improved voltage security. This is confirmed by the loadings on the Sammis-Star at 15:42 EDT, after the loss of Star-South

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Canton—fully 96% of the current on that line was to serve FE load and FE-related transactions, and a cut of *every non-FE through transaction* flowing across northeast Ohio would have obtained only 59 MW (4%) of relief for this specific line. This means that redispatch of generation beyond northeast Ohio would have had almost no impact upon conditions within the Cleveland-Akron area (which after 13:31 EDT had no remaining generation reserves). Equally important, cutting flows on the Star-South Canton line might not have changed subsequent events—because the line opened three times that afternoon due to tree contacts, reducing its loading would not have assured its continued operation.

Power flow patterns on August 14 did not cause the blackout in the Cleveland-Akron area. But once the first four FirstEnergy lines went down, the magnitude and pattern of flows on the overall system did affect the ultimate path, location and speed of the cascade after 16:05:57 EDT.³

Voltages and Voltage Criteria

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed across parts of northern Ohio because of high air conditioning demand and other loads, and power transfers into and to a lesser extent across the region. Voltage varies by location across an electrical region, and operators monitor voltages continuously at key locations across their systems.

Entities manage voltage using long-term planning and day-ahead planning for adequate reactive supply, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. Within Ohio, FE began preparations early in the afternoon of August 14, requesting capacitors to be restored to service⁴ and additional voltage support from generators.⁵ As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, and transformer tap changes to respond to changing voltage conditions.

Voltages at key FirstEnergy buses (points at which lines, generators, transformers, etc., converge)

were declining over the afternoon of August 14. Actual measured voltage levels at the Star bus and others on FE's transmission system on August 14 were below 100% starting early in the day. At 11:00 EDT, voltage at the Star bus equaled 98.5%, declined to 97.3% after the loss of Eastlake 5 at 13:31 EDT, and dropped to 95.9% at 15:05 EDT after the loss of the Harding-Chamberlin line. FirstEnergy system operators reported this voltage performance to be typical for a warm summer day on the FirstEnergy system. The gradual decline of voltage over the early afternoon was consistent with the increase of load over the same time period, particularly given that FirstEnergy had no additional generation within the Cleveland-Akron area load pocket to provide additional reactive support.

Cause 1 Inadequate System Understanding

NERC and regional reliability councils' planning criteria and operating policies (such as NERC I.A and I.D, NPCC A-2, and ECAR Document 1) specify voltage criteria in such generic terms as: acceptable voltages under normal and emergency conditions shall be maintained within normal limits and applicable emergency limits respectively, with due recognition to avoiding voltage instability and widespread system collapse in the event of certain contingencies. Each system then defines its own

Do ATC and TTC Matter for Reliability?

Each transmission provider calculates Available Transfer Capability (ATC) and Total Transfer Capability (TTC) as part of its Open Access Transmission Tariff, and posts those on the OASIS to enable others to plan power purchase transactions. TTC is the forecast amount of electric power that can be transferred over the interconnected transmission network in a reliable manner under specific system conditions. ATCs are forecasts of the amount of transmission available for additional commercial trade above projected committed uses. These are not real-time operating security limits for the grid.

The monthly TTC and ATC values for August 2003 were first determined a year previously; those for August 14, 2003 were calculated 30 days in advance; and the hourly TTC and ATC values for the afternoon of August 14 were calculated approximately seven days ahead using forecasted system conditions. Each of these values should be updated as the forecast of system

conditions changes. Thus the TTC and ATC are advance estimates for commercial purposes and do not directly reflect actual system conditions. NERC's operating procedures are designed to manage actual system conditions, not forecasts such as ATC and TTC.

Within ECAR, ATCs and TTCs are determined on a first contingency basis, assuming that only the most critical system element may be forced out of service during the relevant time period. If actual grid conditions—loads, generation dispatch, transaction requests, and equipment availability—differ from the conditions assumed previously for the ATC and TTC calculation, then the ATC and TTC have little relevance for actual system operations. Regardless of what pre-calculated ATC and TTC levels may be, system operators must use real-time monitoring and contingency analysis to track and respond to real-time facility loadings to assure that the transmission system is operated reliably.

acceptable voltage criteria based on its own system design and equipment characteristics, detailing quantified measures including acceptable minimum and maximum voltages in percentages of nominal voltage and acceptable voltage

declines from the pre-contingency voltage. Good utility practice requires that these determinations be based on a full set of V-Q (voltage performance V relative to reactive power supply Q) and P-V (real power transfer P relative to voltage V)

Competition and Increased Electric Flows

Besides blaming high inter-regional power flows for causing the blackout, some blame the existence of those power flows upon wholesale electric competition. Before 1978, most power plants were owned by vertically-integrated utilities; purchases between utilities occurred when a neighbor had excess power at a price lower than other options. A notable increase in inter-regional power transfers occurred in the mid-1970s after the oil embargo, when eastern utilities with a predominance of high-cost oil-fired generation purchased coal-fired energy from Midwestern generators. The 1970s and 1980s also saw the development of strong north-to-south trade between British Columbia and California in the west, and Ontario, Québec, and New York-New England in the east. Americans benefited from Canada's competitively priced hydroelectricity and nuclear power while both sides gained from seasonal and daily banking and load balancing—Canadian provinces had winter peaking loads while most U.S. utilities had primarily summer peaks.

In the United States, wholesale power sales by independent power producers (IPPs) began after passage of the Public Utility Regulatory Policy Act of 1978, which established the right of non-utility producers to operate and sell their energy to utilities. This led to extensive IPP development in the northeast and west, increasing in-region and inter-regional power sales as utility loads grew without corresponding utility investments in transmission. In 1989, investor-owned utilities purchased 17.8% of their total energy (self-generation plus purchases) from other utilities and IPPs, compared to 37.3% in 2002; and in 1992, large public power entities purchased 36.3% of total energy (self-generation plus purchases), compared to 40.5% in 2002.^a

In the Energy Policy Act of 1992, Congress continued to promote the development of

competitive energy markets by introducing exempt wholesale generators that would compete with utility generation in wholesale electric markets (see Section 32 of the Public Utility Holding Company Act). Congress also broadened the authority of the Federal Energy Regulatory Commission to order transmission access on a case-by-case basis under Section 211 of the Federal Power Act. Consistent with this Congressional action, the Commission in Order 888 ordered all public utilities that own, operate, or control interstate transmission facilities to provide open access for sales of energy transmitted over those lines.

Competition is not the only thing that has grown over the past few decades. Between 1986 and 2002, peak demand across the United States grew by 26%, and U.S. electric generating capacity grew by 22%,^b but U.S. transmission capacity grew little beyond the interconnection of new power plants. Specifically, “the amount of transmission capacity per unit of consumer demand declined during the past two decades and . . . is expected to drop further in the next decade.”^c

Load-serving entities today purchase power for the same reason they did before the advent of competition—to serve their customers with low-cost energy—and the U.S. Department of Energy estimates that Americans save almost \$13 billion (U.S.) annually on the cost of electricity from the opportunity to buy from distant, economical sources. But it is likely that the increased loads and flows across a transmission grid that has experienced little new investment is causing greater “stress upon the hardware, software and human beings that are the critical components of the system.”^d A thorough study of these issues has not been possible as part of the Task Force's investigation, but such a study would be worthwhile. For more discussion, see Recommendation 12, page 148.

^aRDI PowerDat database.

^bU.S. Energy Information Administration, *Energy Annual Data Book*, 2003 edition.

^cDr. Eric Hirst, “Expanding U.S. Transmission Capacity,” August 2000, p. vii.

^dLetter from Michael H. Dworkin, Chairman, State of Vermont Public Service Board, February 11, 2004, to Alison Silverstein and Jimmy Glotfelty.

analyses for a wide range of system conditions. Table 4.3 compares the voltage criteria used by FirstEnergy and other relevant transmission operators in the region. As this table shows, FE uses minimum acceptable normal voltages which are lower than and incompatible with those used by its interconnected neighbors.

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Cause 1
Inadequate System Understanding

The investigation team probed deeply into voltage management issues within the Cleveland-Akron area. As noted previously, a power system with higher operating voltage and larger reactive power reserves is more resilient or robust in the face of load increases and operational contingencies. Higher transmission voltages enable higher power transfer capabilities and reduce transmission line losses (both real and reactive). For the Cleveland-Akron area, FE has been operating the system with the minimum voltage level at 90% of nominal rating, with alarms set at 92%.⁶ The criteria allow for a single contingency to occur if voltage remains above 90%. The team conducted extensive voltage stability studies (discussed below), concluding that FE's 90% minimum voltage level was not only far less stringent than nearby interconnected systems (most of which set the pre-contingency minimum voltage criteria at 95%), but was not adequate for secure system operations.

Examination of the Form 715 filings made by Ohio Edison, FE's predecessor company, for 1994 through 1997 indicate that Ohio Edison used a pre-contingency bus voltage criteria of 95 to 105 % and 90% emergency post-contingency voltage, with acceptable change in voltage no greater than 5%. These historic criteria were compatible with neighboring transmission operator practices.

A look at voltage levels across the region illustrates the difference between FE's voltage situation on August 14 and that of its neighbors.

Cause 1
Inadequate System Understanding

Figure 4.7 shows the profile of voltage levels at key buses from southeast Michigan across Ohio into western Pennsylvania from August 11 through 14 and for several hours on August 14. These transects show that across the area, voltage levels were consistently lower at the 345-kV buses in the Cleveland-Akron area (from Beaver to Hanna on the west to east plot and from Avon Lake to Star on the north to south plot) for the three days and the 13:00 to 15:00 EDT period preceding the blackout. Voltage was consistently and considerably higher at the outer ends of each transect, where it never dropped below 96% even on August 14. These profiles also show clearly the decline of voltage over the afternoon of August 14, with voltage at the Harding bus at 15:00 EDT just below 96% before the Harding-Chamberlin line tripped at 15:05 EDT, and dropping down to around 93% at 16:00 EDT after the loss of lines and load in the immediate area.

Cause 1
Inadequate System Understanding

Using actual data provided by FE, ITC, AEP and PJM, Figure 4.8 shows the availability of reactive reserves (the difference between reactive power generated and the maximum reactive capability) within the Cleveland-Akron area and four regions surrounding it, from ITC to PJM. On the afternoon of August 14, the graph shows that reactive power generation was heavily taxed in the Cleveland-Akron area but that extensive MVAR reserves were available in the neighboring areas. As the afternoon progressed, reactive reserves diminished for all five regions as load grew. But reactive reserves were fully depleted within the Cleveland-Akron area by 16:00 EDT without drawing down the reserves in neighboring areas, which remained at scheduled voltages. The region as a whole had sufficient reactive reserves, but because reactive power cannot be transported far but must be supplied from

Table 4.3. Comparison of Voltage Criteria (Percent)

345 kV/138 kV	FE	PJM	AEP	METC ^a	ITC ^b	MISO	IMO ^c
High	105	105	105	105	105	105	110
Normal Low	90	95	95	97	95	95	98
Emergency/Post N-1 Low	90	92	90 ^d		87		94
Maximum N-1 deviation	5 ^e			5			10

^aApplies to 138 kV only. 345 kV not specified.

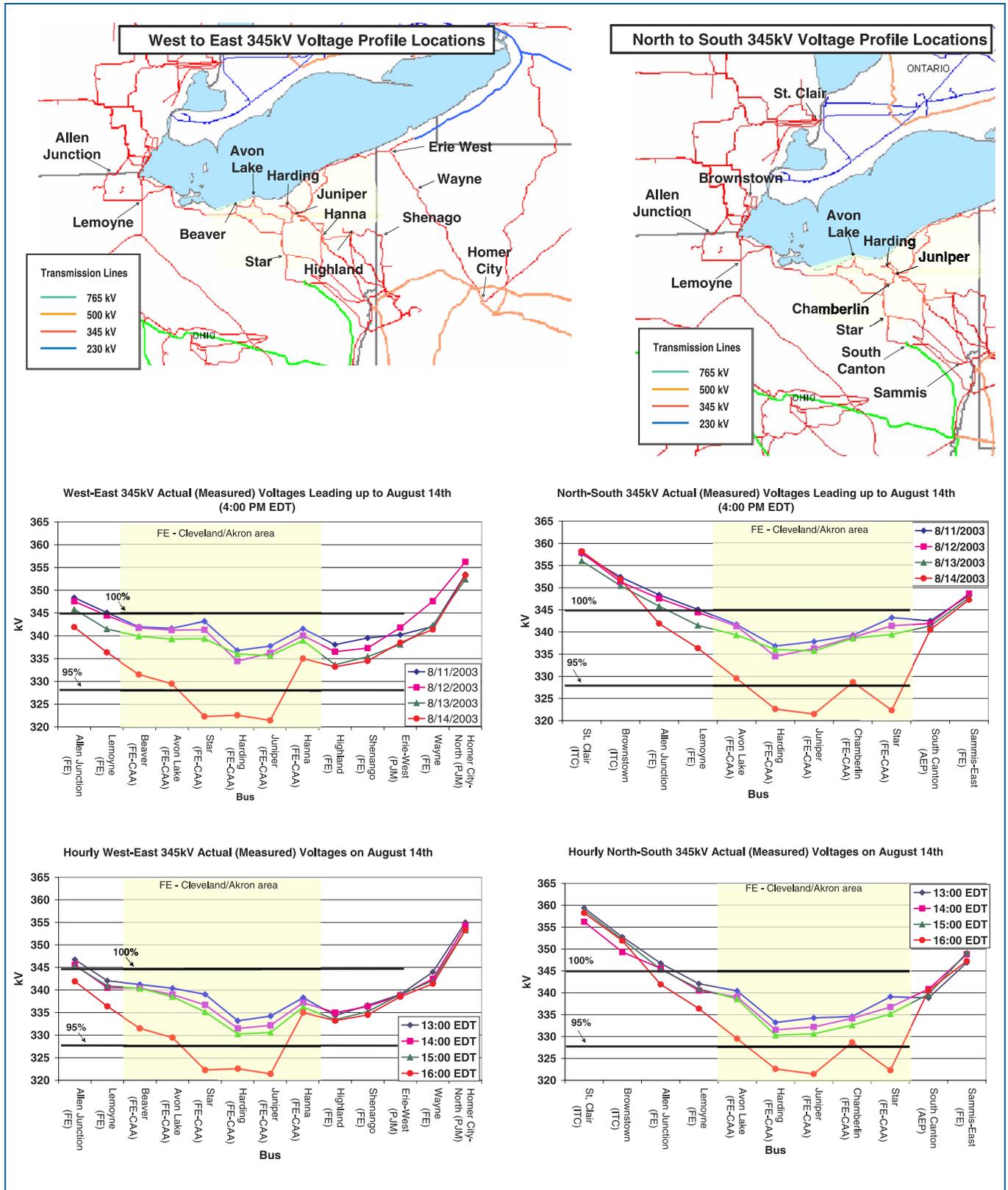
^bApplies to 345 kV only. Min-max normal voltage for 120 kV and 230 kV is 93-105%.

^c500 kV.

^d92% for 138 kV.

^e10% for 138 kV.

Figure 4.7. Actual Voltages Across the Ohio Area Before and On August 14, 2003



Voltage Stability Analysis

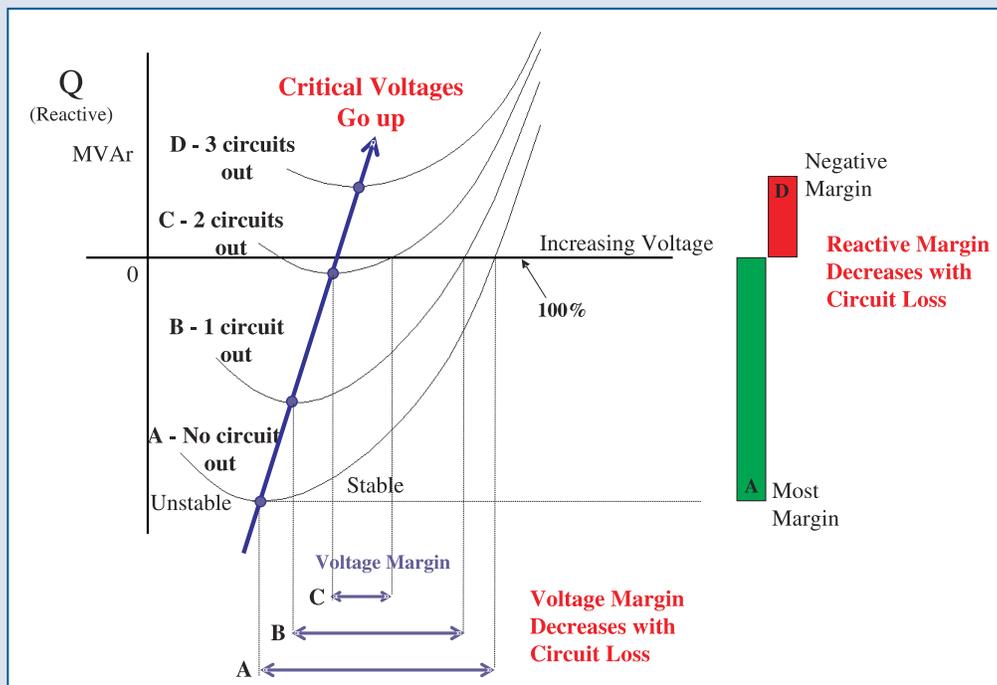
Voltage instability or voltage collapse occurs on a power system when voltages progressively decline until stable operating voltages can no longer be maintained. This is precipitated by an imbalance of reactive power supply and demand, resulting from one or more changes in system conditions including increased real or reactive loads, high power transfers, or the loss of generation or transmission facilities. Unlike the phenomenon of transient instability, where generators swing out of synchronism with the rest of the power system within a few seconds or less after a critical fault, voltage instability can occur gradually within tens of seconds or minutes.

Voltage instability is best studied using V-Q (voltage relative to reactive power) and P-V (real power relative to voltage) analysis. V-Q analysis evaluates the reactive power required at a bus to maintain stable voltage at that bus. A simulated reactive power source is added to the bus, the voltage schedule at the bus is adjusted in small steps from an initial operating point, and power flows are solved to determine the change in reactive power demand resulting from the change in voltage. Under stable operating conditions, when voltage increases the reactive power requirement also increases, and when voltage

falls the reactive requirement also falls. But when voltage is lowered at the bus and the reactive requirement at that bus begins to increase (rather than continuing to decrease), the system becomes unstable. The voltage point corresponding to the transition from stable to unstable conditions is known as the “critical voltage,” and the reactive power level at that point is the “reactive margin.” The desired operating voltage level should be well above the critical voltage with a large buffer for changes in prevailing system conditions and contingencies. Similarly, reactive margins should be large to assure robust voltage levels and secure, stable system performance.

The illustration below shows a series of V-Q curves. The lowest curve, A, reflects baseline conditions for the grid with all facilities available. Each higher curve represents the same loads and transfers for the region modeled, but with another contingency event (a circuit loss) occurring to make the system less stable. With each additional contingency, the critical voltage rises (the point on the horizontal axis corresponding to the lowest point on the curve) and the reactive margin decreases (the difference between the reactive power at the critical voltage and the zero point on the vertical axis). This means the system is closer to instability.

V-Q (Voltage-Reactive Power) Curves



local sources, these healthy reserves nearby could not support the Cleveland-Akron area's reactive power deficiency and growing voltage problems. Even FE's own generation in the Ohio Valley had reactive reserves that could not support the sagging voltages inside the Cleveland-Akron area.

Cause 1
Inadequate System Understanding

An important consideration in reactive power planning is to ensure an appropriate balance between static and dynamic reactive power resources across the interconnected system (as specified in NERC Planning Standard 1D.S1). With so little generation left in the Cleveland-Akron area on August 14, the area's dynamic reactive reserves were depleted and the area relied heavily on static compensation to respond to changing system conditions and support voltages. But a system relying on static compensation can experience a gradual voltage degradation followed by a sudden drop in voltage stability—the P-V curve for such a system has a very steep slope close to the nose, where voltage collapses. On August 14, the lack of adequate dynamic reactive reserves, coupled with not knowing the critical voltages and maximum import capability to serve native load, left the Cleveland-Akron area in a very vulnerable state.

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Past System Events and Adequacy of System Studies

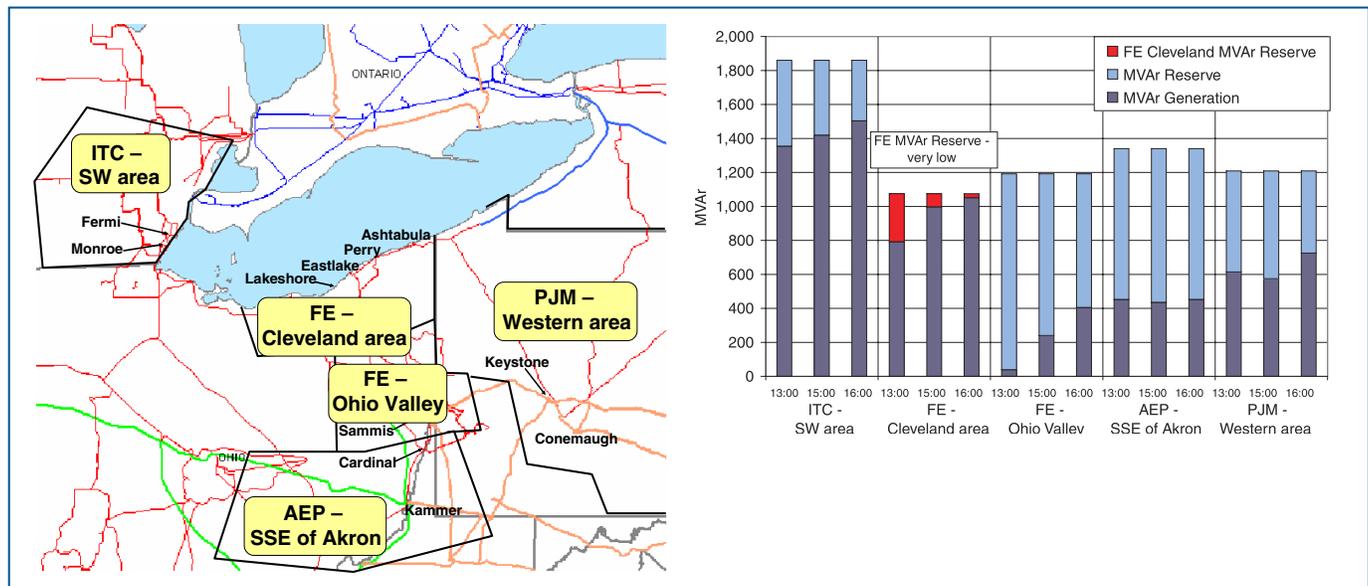
Cause 1
Inadequate System Understanding

In June 1994, with three generators in the Cleveland area out on maintenance, inadequate reactive reserves and falling voltages in the Cleveland area forced Cleveland Electric Illuminating (CEI, a predecessor company to FirstEnergy) to shed load within Cleveland (a municipal utility and wholesale transmission and purchase customers within CEI's control area) to avoid voltage collapse.⁷ The Cleveland-Akron area's voltage problems were well-known and reflected in the stringent voltage criteria used by control area operators until 1998.⁸

Cause 1
Inadequate System Understanding

In the summer of 2002, AEP's South Canton 765 kV to 345 kV transformer (which connects to FirstEnergy's Star 345-kV line) experienced eleven days of severe overloading when actual loadings exceeded normal rating and contingency loadings were at or above summer emergency ratings. In each instance, AEP took all available actions short of load shedding to return the system to a secure state, including TLRs, switching, and dispatch adjustments. These excessive loadings were

Figure 4.8. Reactive Reserves Around Ohio on August 14, 2003, for Representative Generators in the Area



Note: These reactive reserve MVar margins were calculated for the five regions for the following plants: (1) Cleveland area of FirstEnergy—Ashtabula 5, Perry 1, Eastlake 1, Eastlake 3, Lakeshore 18; (2) Northern central portion of AEP near FirstEnergy (South-Southeast of Akron)—Cardinal 1, Cardinal 2, Cardinal 3, Kammer 2, Kammer 3; (3) Southwest area of MECS (ITC)—Fermi 1, Monroe 2, Monroe 3, Monroe 4; (4) Ohio Valley portion of FirstEnergy—Sammis 4, Sammis 5, Sammis 6, Sammis 7; (5) Western portion of PJM—Keystone 1, Conemaugh 1, Conemaugh 2.

calculated to have diminished the remaining life of the transformer by 30%. AEP replaced this single phase transformer in the winter of 2002-03, marginally increasing the capacity of the South Canton transformer bank.

Following these events, AEP conducted extensive modeling to understand the impact of a potential outage of this transformer. That modeling revealed that loss of the South Canton transformer,

especially if it occurred in combination with outages of other critical facilities, would cause significant low voltages and overloads on both the AEP and FirstEnergy systems. AEP shared these findings with FirstEnergy in a meeting on January 10, 2003.⁹

AEP subsequently completed a set of system studies, including long range studies for 2007, which included both single contingency and extreme

Independent Power Producers and Reactive Power

Independent power producers (IPPs) are power plants that are not owned by utilities. They operate according to market opportunities and their contractual agreements with utilities, and may or may not be under the direct control of grid operators. An IPP's reactive power obligations are determined by the terms of its contractual interconnection agreement with the local transmission owner. Under routine conditions, some IPPs provide limited reactive power because they are not required or paid to produce it; they are only paid to produce active power. (Generation of reactive power by a generator can require scaling back generation of active power.) Some contracts, however, compensate IPPs for following a voltage schedule set by the system operator, which requires the IPP to vary its output of reactive power as system conditions change. Further, contracts typically require increased reactive power production from IPPs when it is requested

by the control area operator during times of a system emergency. In some contracts, provisions call for the payment of opportunity costs to IPPs when they are called on for reactive power (i.e., they are paid the value of foregone active power production).

Thus, the suggestion that IPPs may have contributed to the difficulties of reliability management on August 14 because they don't provide reactive power is misplaced. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available.

Power Flow Simulation of Pre-Cascade Conditions

The bulk power system has no memory. It does not matter if frequencies or voltage were unusual an hour, a day, or a month earlier. What matters for reliability are loadings on facilities, voltages, and system frequency at a given moment and the collective capability of these system components at that same moment to withstand a contingency without exceeding thermal, voltage, or stability limits.

Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer a series of "what if" questions to determine whether the system was in a safe operating state at that time. The "what if" questions consist of systematically simulating outages by removing key elements (e.g., generators or trans-

mission lines) one by one and reassessing the system each time to determine whether line or voltage limits would be exceeded. If a limit is exceeded, the system is not in a secure state. As described in Chapter 2, NERC operating policies require operators, upon finding that their system is not in a reliable state, to take immediate actions to restore the system to a reliable state as soon as possible and within a maximum of 30 minutes.

To analyze the evolution of the system on the afternoon of August 14, this process was followed to model several points in time, corresponding to key transmission line trips. For each point, three solutions were obtained: (1) conditions immediately before a facility tripped off; (2) conditions immediately after the trip; and (3) conditions created by any automatic actions taken following the trip.

disturbance possibilities. These studies showed that with heavy transfers to the north, expected overloading of the South Canton transformer and depressed voltages would occur following the loss of the Perry unit and the loss of the Tidd-Canton Central 345-kV line, and probable cascading into voltage collapse across northeast Ohio would occur for nine different double contingency combinations of generation and transmission or transmission and transmission outages.¹⁰ AEP shared these findings with FirstEnergy in a meeting on May 21, 2003. Meeting notes indicate that “neither AEP or FE were able to identify any changes in transmission configuration or operating procedures which could be used during 2003 summer to be able to control power flows through the S. Canton bank.”¹¹ Meeting notes include an action item that both “AEP and FE would share the results of these studies and expected performance for 2003 summer with their Management and Operations personnel.”¹²

Reliability coordinators and control areas prepare regional and seasonal studies for a variety of system-stressing scenarios, to better understand potential operational situations, vulnerabilities, risks, and solutions. However, the studies FirstEnergy relied on—both by FirstEnergy and ECAR—were not robust, thorough, or up-to-date. This left FE’s planners and operators with a deficient understanding of their system’s capabilities and risks under a range of system conditions. None of the past voltage events noted above or the significant risks identified in AEP’s 2002-2003 studies are reflected in any FirstEnergy or ECAR seasonal or longer-term planning studies or operating protocols available to the investigation team.

Cause 1
Inadequate System Understanding

FE’s 2003 Summer Study focused primarily on single-contingency (N-1) events, and did not consider significant multiple contingency losses and security. FirstEnergy examined only thermal limits and looked at voltage only to assure that voltage levels remained within range of 90 to 105% of nominal voltage on the 345 kV and 138 kV network. The study assumed that only the Davis-Besse power plant (883 MW) would be out of service at peak load of 13,206 MW; on August 14, peak load reached 12,166 MW and scheduled generation outages included Davis-Besse, Sammis 3 (180 MW) and Eastlake 4 (240 MW), with Eastlake 5 (597 MW) lost in real time. The study assumed that all transmission facilities would be in service; on August 14, scheduled transmission outages included the

Eastlake #62 345/138 kV transformer and the Fox #1 138-kV capacitor, with other capacitors down in real time. Last, the study assumed a single set of import and export conditions, rather than testing a wider range of generation dispatch, import-export, and inter-regional transfer conditions. Overall, the summer study posited less stressful system conditions than actually occurred August 14, 2003 (when load was well below historic peak demand). It did not examine system sensitivity to key parameters to determine system operating limits within the constraints of transient stability, voltage stability, and thermal capability.

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Cause 1
Inadequate System Understanding

FirstEnergy has historically relied upon the ECAR regional assessments to identify anticipated reactive power requirements and recommended corrective actions. But ECAR over the past five years has not conducted any detailed analysis of the Cleveland-Akron area and its voltage-constrained import capability—although that constraint had been an operational consideration in the 1990s and was documented in testimony filed in 1996 with the Federal Energy Regulatory Commission.¹³ The voltage-constrained import capability was not studied; FirstEnergy had modified the criteria around 1998 and no longer followed the tighter voltage limits used earlier. In the ECAR “2003 Summer Assessment of Transmission System Performance,” dated May 2003, First Energy’s Individual Company Assessment identified potential overloads for the loss of both Star 345/138 transformers, but did not mention any expected voltage limitation.

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FE participates in ECAR studies that evaluate extreme contingencies and combinations of events. ECAR does not conduct exacting region-wide analyses, but compiles individual members’ internal studies of N-2 and multiple contingencies (which may include loss of more than one circuit, loss of a transmission corridor with several transmission lines, loss of a major substation or generator, or loss of a major load pocket). The last such study conducted was published in 2000, projecting system conditions for 2003. That study did not include any contingency cases that resulted in 345-kV line overloading or voltage violations on 345-kV buses. FE reported no evidence of a risk of cascading, but reported that some local load would be lost and generation redispatch would be needed to alleviate some thermal overloads.

ECAR and Organizational Independence

ECAR was established in 1967 as a regional reliability council, to “augment the reliability of the members’ electricity supply systems through coordination of the planning and operation of the members’ generation and transmission facilities.”^a ECAR’s membership includes 29 major electricity suppliers serving more than 36 million people.

ECAR’s annual budget for 2003 was \$5.15 million (U.S.), including \$1.775 million (U.S.) paid to fund NERC.^b These costs are funded by its members in a formula that reflects megawatts generated, megawatt load served, and miles of high voltage lines. AEP, ECAR’s largest member, pays about 15% of total ECAR expenses; FirstEnergy pays approximately 8 to 10%.^c

Utilities “whose generation and transmission have an impact on the reliability of the interconnected electric systems” of the region are full ECAR members, while small utilities, independent power producers, and marketers can be associate members.^d Its Executive Board has 22 seats, one for each full member utility or major supplier (including every control area operator in ECAR). Associate members do not have voting rights, either on the Board or on the technical committees which do all the work and policy-setting for the ECAR region.

All of the policy and technical decisions for ECAR, including all interpretations of NERC guidelines, policies, and standards within ECAR, are developed by committees (called “panels”), staffed by representatives from the ECAR member companies. Work allocation and leadership within ECAR are provided by the Board, the Coordination Review Committee, and the Market Interface Committee.

ECAR has a staff of 18 full-time employees, headquartered in Akron, Ohio. The staff provides engineering analysis and support to the various committees and working groups. Ohio Edison, a FirstEnergy subsidiary, administers salary, benefits, and accounting services for ECAR. ECAR employees automatically become part of Ohio Edison’s (FirstEnergy’s) 401(k) retirement plan; they receive FE stock as a matching share to employee 401(k) investments and can purchase FE stock as well. Neither ECAR staff nor board members are required to divest stock holdings in ECAR member companies.^e Despite the close link between FirstEnergy’s financial health and the interest of ECAR’s staff and management, the investigation team has found no evidence to suggest that ECAR staff favor FirstEnergy’s interests relative to other members.

ECAR decisions appear to be dominated by the member control areas, which have consistently allowed the continuation of past practices within each control area to meet NERC requirements, rather than insisting on more stringent, consistent requirements for such matters as operating voltage criteria or planning studies. ECAR member representatives also staff the reliability council’s audit program, measuring individual control area compliance against local standards and interpretations. It is difficult for an entity dominated by its members to find that the members’ standards and practices are inadequate. But it should also be recognized that NERC’s broadly worded and ambiguous standards have enabled and facilitated the lax interpretation of reliability requirements within ECAR over the years.

Recommendations
2, page 143; 3, page 143

^aECAR “Executive Manager’s Remarks,” <http://www.ecar.org>.

^bInterview with Brantley Eldridge, ECAR Executive Manager, March 10, 2004.

^cInterview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

^dECAR “executive Manager’s Remarks,” <http://www.ecar.org>.

^eInterview with Brantley Eldridge, ECAR Executive Manager, March 3, 2004.

Model-Based Analysis of the State of the Regional Power System at 15:05 EDT, Before the Loss of FE’s Harding-Chamberlin 345-kV Line

As the first step in modeling the August 14 blackout, the investigation team established a base case by creating a power flow simulation for the entire Eastern Interconnection and benchmarking it to recorded system conditions at 15:05 EDT on August 14. The team started with a projected summer 2003 power flow case for the Eastern Interconnection developed in the spring of 2003 by the Regional Reliability Councils to establish guidelines for safe operations for the coming summer. The level of detail involved in this region-wide power flow case far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses, 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 EDT on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid. Thousands of hours of effort were required to benchmark the model satisfactorily to observed conditions at 15:05 EDT.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events—including the loss of the Harding-Chamberlin 345-kV line—as points of departure from the 15:05 EDT case. None of these contingencies resulted in a violation of a transmission line loading or bus voltage limit prior to the trip of FE’s Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was capable of safe operation following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, *before* 15:05 EDT the Eastern Interconnection was being operated within all established limits and in full compliance with NERC’s operating policies. However, *after* loss of the Harding-Chamberlin 345-kV line, the system would have exceeded emergency ratings immediately on several lines for two of the contingencies studied—in other words, it would no longer be operating in compliance with NERC Operating Policy A.2 because it could not be

brought back into a secure operating condition within 30 minutes.

Perry Nuclear Plant as a First Contingency

Investigation team modeling demonstrates that the Perry nuclear unit (1,255 MW near Lake Erie) is critical to the voltage stability of the Cleveland-Akron area in general and particularly on August 14. The modeling reveals that had Perry tripped before 15:05 EDT, voltage levels at key FirstEnergy buses would have fallen close to 93% with only a 150 MW of area load margin (2% of the Cleveland-Akron area load); but had Perry been lost after the Harding-Chamberlin line went down at 15:05 EDT, the Cleveland-Akron area would have been close to voltage collapse.

Cause 1
Inadequate
System
Understanding

Perry and Eastlake 5 together have a combined real power capability of 1,852 MW and reactive capability of 930 MVar. If one of these units is lost, it is necessary to immediately replace the lost generation with MW and MVar imports (although reactive power does not travel far under heavy loading); without quick-start generation or spinning reserves or dynamic reactive reserves inside the Cleveland-Akron area, system security may be jeopardized. On August 14, as noted previously, there were no significant spinning reserves remaining within the Cleveland-Akron area following the loss of Eastlake 5 at 13:31 EDT. If Perry had been lost FE would have been unable to meet the 30-minute security adjustment requirement of NERC’s Operating Policy 2, without the ability to shed load quickly. The loss of Eastlake 5 followed by the loss of Perry are contingencies that should be assessed in the operations planning timeframe, to develop measures to readjust the system between contingencies. Since FirstEnergy did not conduct such contingency analysis planning and develop these advance measures, it was in violation of NERC Planning Standard 1A, Category C3.

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This operating condition is not news. Historically, the loss of Perry at full output has been recognized as FE’s most critical single contingency for the Cleveland Electric Illuminating area, as documented by FE’s 1998 Summer Import Capability study. Perry’s MW and MVar total output capability exceeded the import capability of any of the critical 345-kV circuits into the Cleveland-Akron area after the loss of Eastlake 5 at 13:31 EDT. This

means that if the Perry plant had been lost on August 14 after Eastlake 5 went down—or on many other days with similar loads and outages—it would have been difficult or impossible for FE operators to adjust the system within 30 minutes to prepare for the next critical contingency, as required by NERC Operating Policy A.2. In real-time operations, operators would have to calculate operating limits and prepare to use the last resort of manually shedding large blocks of load before the second contingency, or immediately after it if automatic load-shedding is available.

Cause 1
Inadequate System Understanding

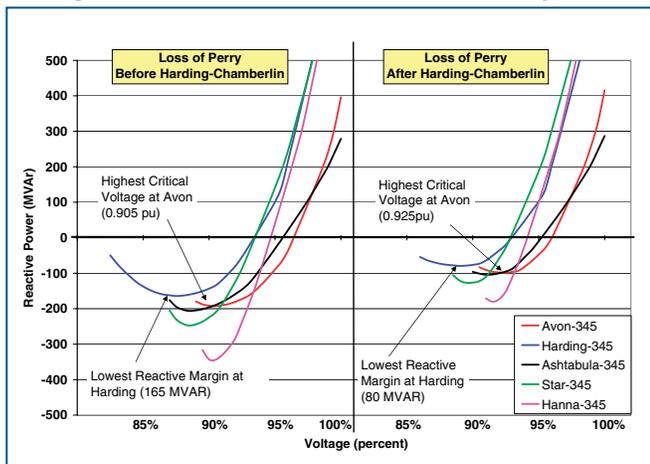
The investigation team could not find FirstEnergy contingency plans or operational procedures for operators to manage the FirstEnergy control area and protect the Cleveland-Akron area from the unexpected loss of the Perry plant.

protect the Cleveland-Akron area from the unexpected loss of the Perry plant.

To examine the impact of this worst contingency on the Cleveland-Akron area on August 14, Figure 4.9 shows the V-Q curves for key buses in the Cleveland-Akron area at 15:05 EDT, before and after the loss of the Harding-Chamberlin line. The curves on the left look at the impact of the loss of Perry before the Harding-Chamberlin trip, while the curves on the right show the impact had the nuclear plant been lost after Harding-Chamberlin went out of service. Had Perry gone down *before* the Harding-Chamberlin outage, reactive margins at key FE buses would have been minimal (with the tightest margin at the Harding bus, read along the Y-axis) and the critical voltage (the point before voltage collapse, read along the X-axis) at

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Figure 4.9. Loss of the Perry Unit Hurts Critical Voltages and Reactive Reserves: V-Q Analyses



the Avon bus would have risen to 90.5%—uncomfortably close to the limits which FE considered as an acceptable operating range. But had the Perry unit gone off-line *after* Harding-Chamberlin, reactive margins at all these buses would have been even tighter (with only 60 MVAR at the Harding bus), and critical voltage at Avon would have risen to 92.5%, worse than FE’s 90% minimum acceptable voltage. The system at this point would be very close to voltage instability. If the first line outage on August 14, 2003, had been at Hanna-Juniper rather than at Harding-Chamberlin, the FirstEnergy system could not have withstood the loss of the Perry plant.

Cause 1
Inadequate System Understanding

The above analysis assumed load levels consistent with August 14. But temperatures were not particularly high that day and loads were nowhere near FE’s historic

load level of 13,229 MW for the control area (in August 2002). Therefore the investigation team looked at what might have happened in the Cleveland-Akron area had loads neared the historic peak—approximately 625 MW higher than the 6,715 MW peak load in the Cleveland-Akron area in 2003. Figure 4.10 uses P-V analysis to show the impact of increased load levels on voltages at the Star bus with and without the Perry unit before the loss of the Harding-Chamberlin line at 15:05 EDT. The top line shows that with the Perry plant available, local load could have increased by 625 MW and voltage at Star would have remained above 95%. But the bottom line, simulating the loss of Perry, indicates that load could only have increased by about 150 MW before voltage at Star would have become unsolvable, indicating no voltage stability margin and depending on load dynamics, possible voltage collapse.

The above analyses indicate that the Cleveland-Akron area was highly vulnerable on the afternoon of August 14. Although the system was compliant with NERC Operating Policy 2A.1 for single contingency reliability before the loss of the Harding-Chamberlin line at 15:05 EDT, had FE lost the Perry plant its system would have neared voltage instability or could have gone into a full voltage collapse immediately if the Cleveland-Akron area load were 150 MW higher. It is worth noting that this could have happened on August 14—at 13:43 EDT that afternoon, the Perry plant operator called the control area operator to warn about low voltages. At 15:36:51 EDT the Perry plant operator called FirstEnergy’s system control center to ask about voltage spikes at the plant’s main

transformer.¹⁴ At 15:42:49 EDT the Perry operator called the FirstEnergy operator to say, “I’m still getting a lot of voltage spikes and swings on the generator . . . I’m taking field volts pretty close to where I’ll trip the turbine off.”¹⁵

System Frequency

Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System frequency is monitored on a continuous basis.

There were no significant or unusual frequency oscillations in the Eastern Interconnection on August 14 prior to 16:09 EDT compared to prior days, and frequency was well within the bounds of safe operating practices. System frequency variation was not a cause or precursor of the initiation of the blackout. But once the cascade began, the large frequency swings that occurred early on became a principal means by which the blackout spread across a wide area.

Figure 4.11 shows Eastern Interconnection frequency on August 14, 2003. Frequency declines or increases from a mismatch between generation and load on the order of about 3,200 MW per 0.1 Hertz (alternatively, a change in load or generation of 1,000 MW would cause a frequency

change of about ± 0.031 Hz). Significant frequency excursions reflect large changes in load relative to generation and could cause unscheduled flows between control areas and even, in the extreme, cause automatic under-frequency load-shedding or automatic generator trips.

The investigation team examined Eastern Interconnection frequency and Area Control Error (ACE) for August 14, 2003 and the entire month of August, looking for patterns and anomalies. Extensive analysis using Fast Fourier Transforms (described in the NERC Technical Report) revealed no unusual variations. Rather, transforms using various time samples of average frequency (from 1 hour to 6 seconds in length) indicate instead that the Eastern Interconnection exhibits regular deviations.¹⁶

The largest deviations in frequency occur at regular intervals. These intervals reflect interchange

Figure 4.10. Impact of Perry Unit Outage on Cleveland-Akron Area Voltage Stability

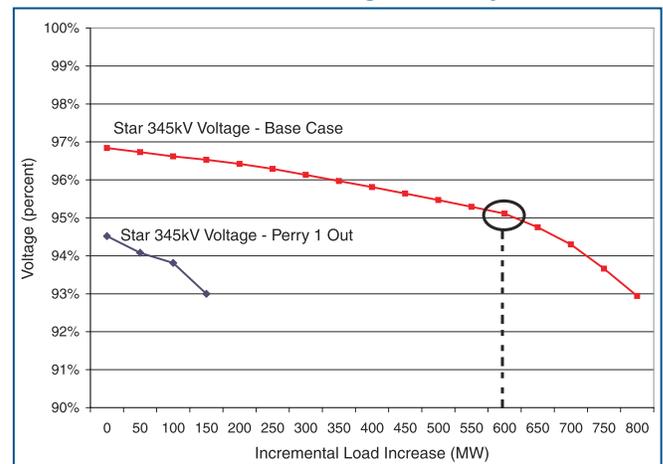
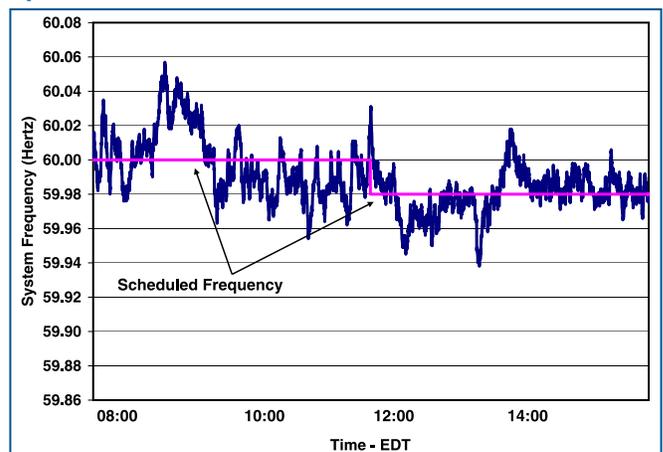


Figure 4.11. Frequency on August 14, 2003, up to 16:09 EDT



Frequency Management

Each control area is responsible for maintaining a balance between its generation and demand. If persistent under-frequency occurs, at least one control area somewhere is “leaning on the grid,” meaning that it is taking unscheduled electricity from the grid, which both depresses system frequency and creates unscheduled power flows. In practice, minor deviations at the control area level are routine; it is very difficult to maintain an exact balance between generation and demand. Accordingly, NERC has established operating rules that specify maximum permissible deviations, and focus on prohibiting persistent deviations, but not instantaneous ones. NERC monitors the performance of control areas through specific measures of control performance that gauge how accurately each control area matches its load and generation.

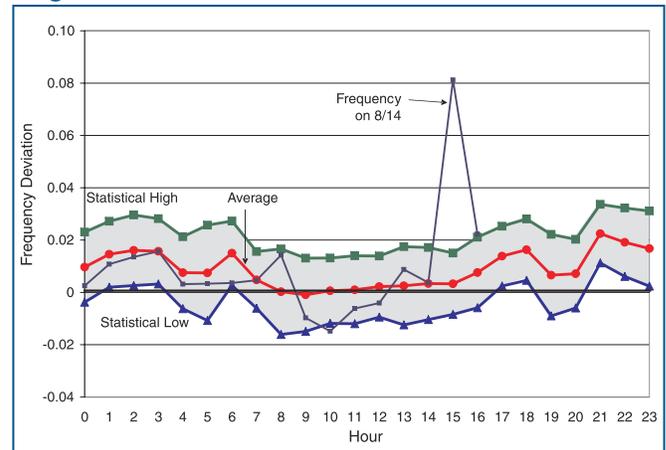
schedule changes at the peak to off-peak schedule changes (06:00 to 07:00 and 21:00 to 22:00, as shown in Figure 4.12) and on regular hourly and half-hour schedule changes as power plants ramp up and down to serve scheduled purchases and interchanges. Frequency tends to run high in the early part of the day because extra generation capacity is committed and waiting to be dispatched for the afternoon peak, and then runs lower in the afternoon as load rises relative to available generation and spinning reserve. The investigation team concluded that frequency data collection and frequency management in the Eastern Interconnection should be improved, but that frequency oscillations before 16:09 EDT on August 14 had no effect on the blackout.

Conclusion

Determining that the system was in a reliable operational state at 15:05 EDT is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a cause of the blackout. This eliminates low voltages earlier in the day or on prior days, the unavailability of individual generators or transmission lines (either individually or in combination with one another), high power flows to Canada, unusual system frequencies, and many other issues as direct, principal or sole causes of the blackout.

Although FirstEnergy's system was technically in secure electrical condition before 15:05 EDT, it was still highly vulnerable, because some of its assumptions and limits were not accurate for safe operating criteria. Analysis of Cleveland-Akron area voltages and reactive margins shows that FirstEnergy was operating that system on the very edge of NERC operational reliability standards, and that it could have been compromised by a number of potentially disruptive scenarios that were foreseeable by thorough planning and operations studies. A system with this little reactive margin would leave little room for adjustment, with few relief actions available to operators in the face of single or multiple contingencies. As the next chapter will show, the vulnerability created by inadequate system planning and understanding was exacerbated because the FirstEnergy operators were not adequately trained or prepared to recognize and deal with emergency situations.

Figure 4.12. Hourly Deviations in Eastern Interconnection Frequency for the Month of August 2003



Endnotes

- 1 FE transcripts, Channel 14, 13:33:44.
- 2 FE transcripts, Channel 14 at 13:21:05; channel 3 at 13:41:54; 15:30:36.
- 3 “ECAR Investigation of August 14, 2003 Blackout by Major System Disturbance Analysis Task Force, Recommendations Report,” page 6.
- 4 Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40. However, no additional capacitors were available.
- 5 From 13:13 through 13:28, reliability operator at FE called nine plant operators to request additional voltage support. Examples at Channel 16, 13:13:18, 13:15:49, 13:16:44, 13:20:44, 13:22:07, 13:23:24, 13:24:38, 13:26:04, 13:28:40.
- 6 DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.
- 7 See 72 FERC 61,040, the order issued for FERC dockets EL 94-75-000 and EL 94-80-000, for details of this incident.
- 8 Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.
- 9 Presentation notes for January 10, 2003 meeting between AEP and FirstEnergy, and meeting summary notes by Paul Johnson, AEP Manager, East Bulk Transmission Planning, January 10, 2003.
- 10 “Talking Points” for May 21, 2003 meeting between AEP and FirstEnergy, prepared by AEP.
- 11 Memo, “Summary of AEP/FE Meeting on 5/21/03,” by Scott P. Lockwood, AEP, May 29, 2003.
- 12 *Ibid.*
- 13 Testimony by Stanley Szwed, Vice President of Engineering and Planning, Centerior Service Company (Cleveland Electric Illuminating Company and Toledo Edison), FERC docket EL 94-75-000, February 22, 1996.
- 14 FE transcript, Channel 8.
- 15 FE transcript, Channel 8.
- 16 See NERC Blackout Investigation Technical Reports, to be released in 2004.