APPENDIX A

OVERVIEW OF THE NORTH AMERICAN ELECTRIC POWER SYSTEM

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.

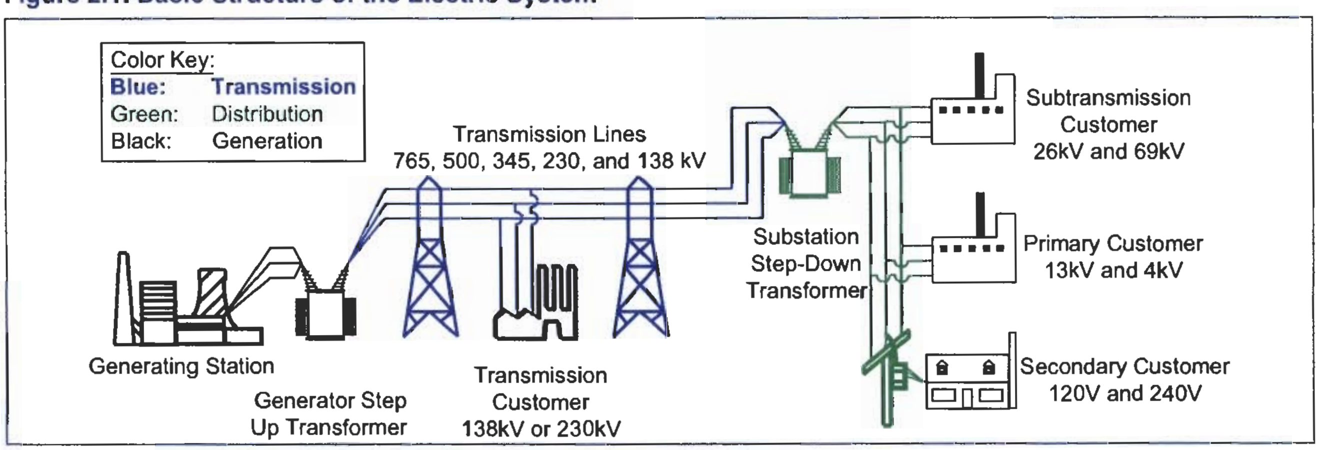
Modern society has come to depend on reliable electricity as an essential resource for national security; health and welfare; communications; finance; transportation; food and water supply; heating, cooling, and lighting; computers and electronics; commercial enterprise; and even entertainment and leisure—in 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

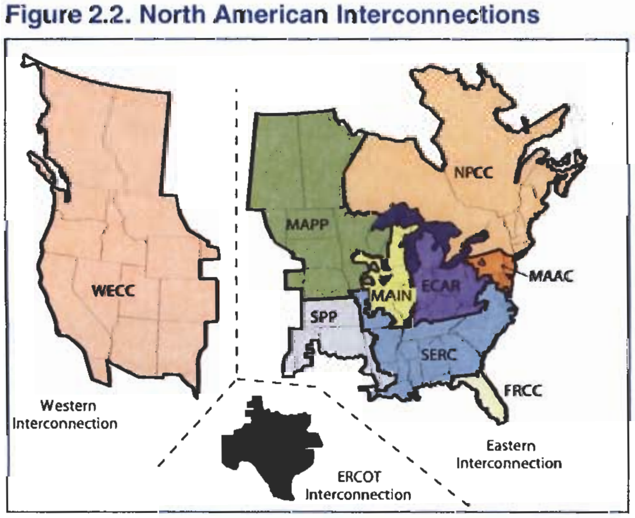
Figure 2.1. Basic Structure of the Electric System



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 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.

Figure 2.2. North American Interconnections



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.

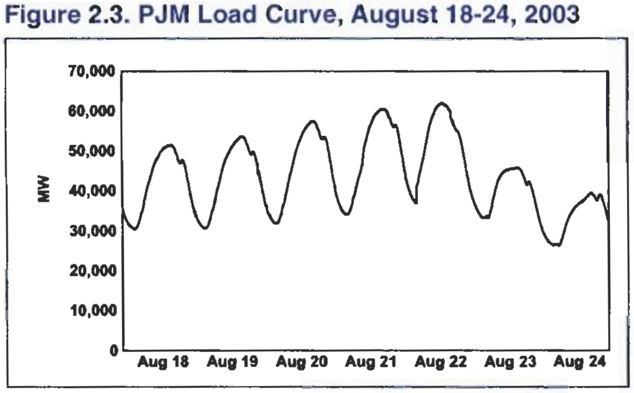
- Keep the system in a stable condition.
- Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N-1 criterion").
- Plan, design, and maintain the system to operate reliably.
- Prepare for emergencies.

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.

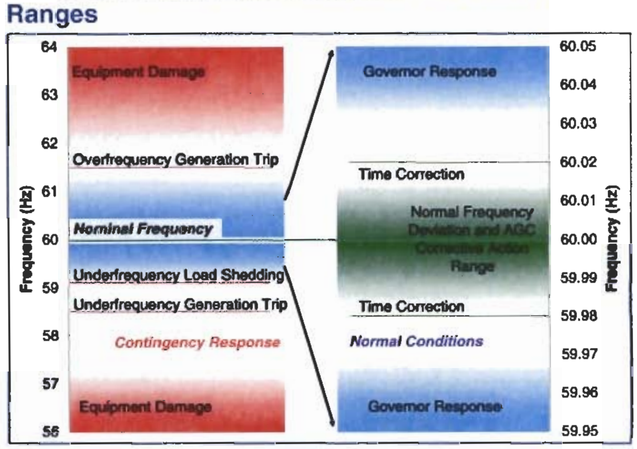
Figure 2.3. PJM Load Curve, August 18-24, 2003



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 2.4. 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.

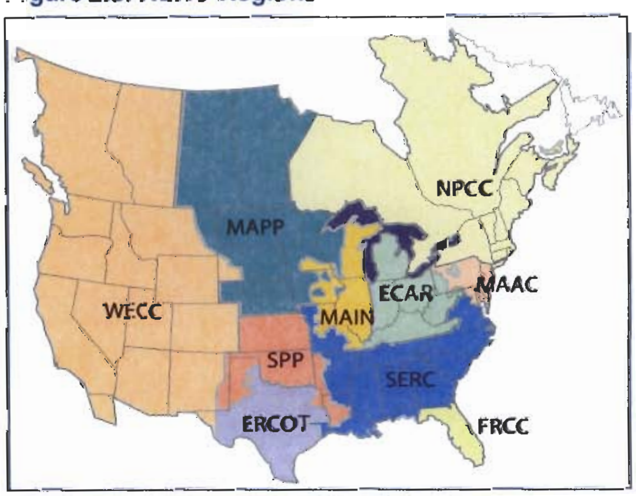
Traditionally, control areas were defined by utility service area boundaries and operations were largely managed by vertically integrated utilities that owned and operated generation, transmission, and distribution. While that is still true in some areas, there has been significant restructuring of operating 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)

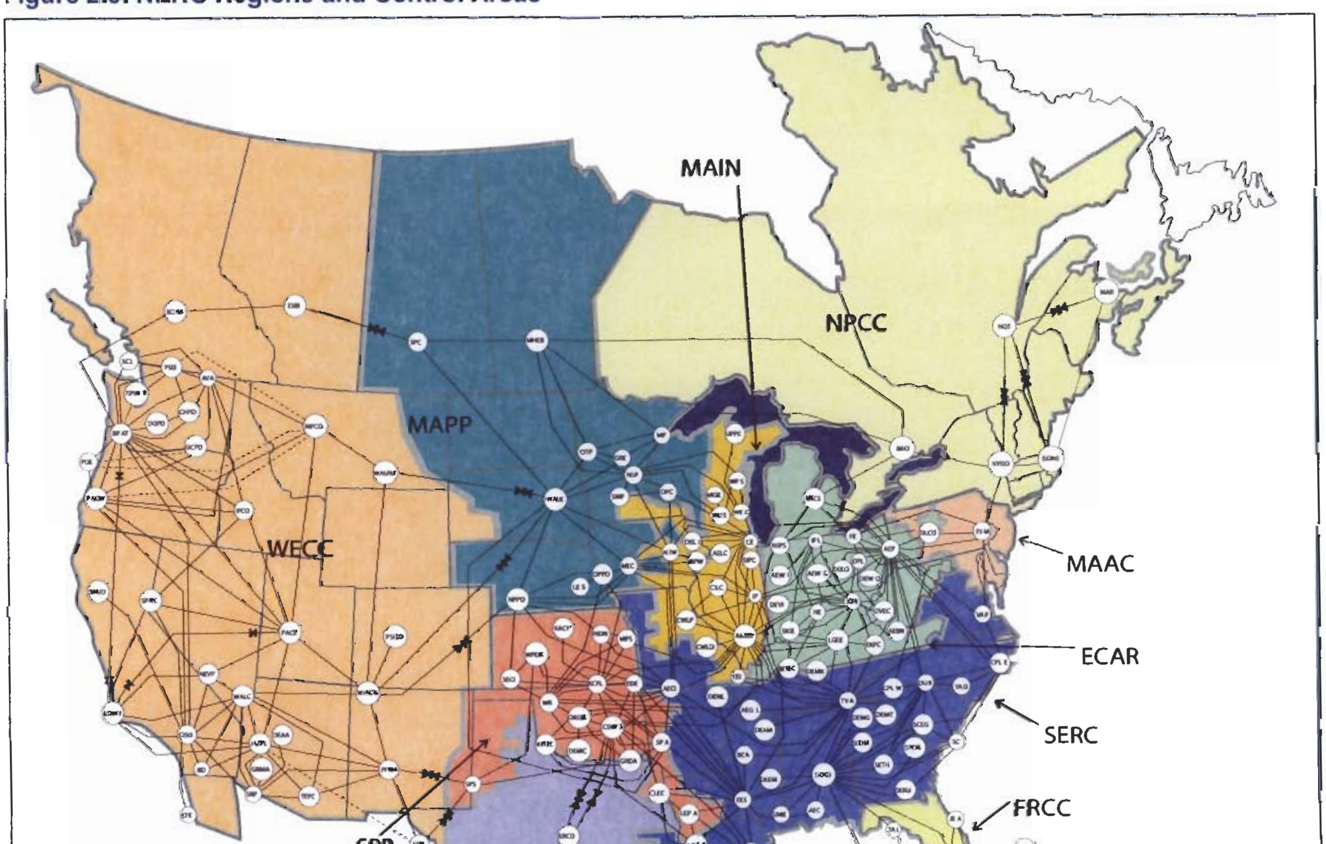
Reliability coordinators provide reliability oversight over a wide region. They prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They may operate, but do not participate in, wholesale or retail market 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

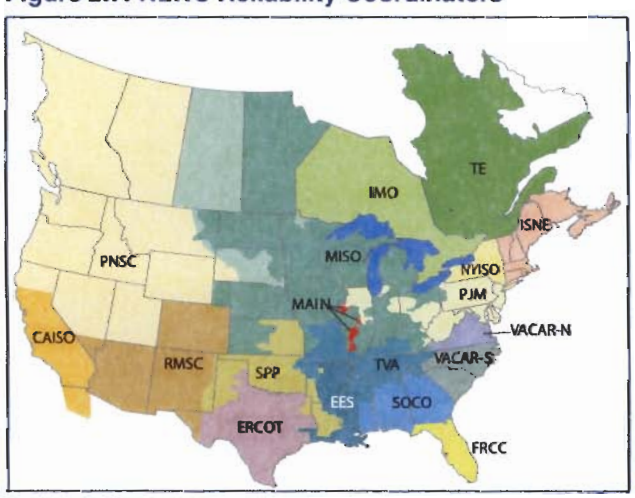
Figure 2.6. NERC Regions and Control Areas



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.