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Chapter 3. Reliability

1. Introduction

The Blackout of August 14, 2003 directly affected about 50 million people in the United States and Canada, leaving millions of them without power. Within a few months of that blackout, the U.S.-Canada Power System Outage Task Force identified its proximate causes.[1] But their study did not address broad public policy questions about the reliability of the electric power system.[2] Reliability refers to the power system's ability to deliver power of specified quality when and where it is desired. Among the questions the Task Force did not address are: (1) How reliable is the grid? (2) Is the grid becoming more or less reliable over time? (3) Are necessary investments in reliability being made, especially in transmission? (4) Do market incentives undermine reliability? In particular, do voluntary approaches to reliability management work in a market setting? (5) Are markets revealing new ways to attain reliability at less cost? This chapter reviews the official data and analytical tools available for answering such questions.

The Federal government's role in reliability management has been to monitor outages and to require investor owned utilities to show their plans are consistent with reliable operations.[3] The Department of Energy also sponsors reliability research, conducts investigations after major outages and works with industry reliability groups to anticipate reliability problems. The Federal Government does not determine acceptable levels of reliability nor does it mandate how reliable performance is to be obtained. That is left to the industry, particularly the North American Electric Reliability Council (NERC). This chapter examines the kinds of data the government needs to carry on reliability oversight.

Since the September 11, 2001 terrorist attacks the government has restricted access to certain grid data that were previously public. The data needed to analyze reliability are a crucial part of the information needed to identify the grid's vulnerabilities to physical attack. Whether the terrorist threat will cause the government to take a more direct role in reliability modeling, analysis and management is an open question. If it does, the government's data needs would only grow.

After the East Coast Blackout of 1965, utilities formed the North American Electric Reliability Council (NERC) to develop voluntary reliability standards and guidelines. NERC encouraged its members in each of its 10 regions (see chapter 2) to maintain

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[1] U.S.-Canada Power System Outage Task Force, *Interim Report: Causes of the August 14th Blackout in the United States and Canada*, November 2003

[2] For examples of differing views see, Richardson, Bill, *Drunk on Power*, Barabasi, Albert-Laszlo, *We're all on the Grid Together*, and Kuttner, Robert, *An Industry Trapped by a Theory*, all in the New York Times, Saturday, August 16, 2003, page A25

[3] The EIA Form 417 collects data on outages and power quality problems. The EIA Form 411 and the FERC Form 715 collect facility and electrical data needed in reliability studies.

enough reserve generation and transmission in their exclusive franchise (service) areas to keep the lights on despite equipment failures and exceptionally large demand. State and Federal regulators generally approved those investments and permitted investors to recover their costs by charging their captive customers. NERC also encouraged its members to coordinate their individual investment plans and responses to reliability threats. Everyone generally cooperated in these efforts because reliable operation is in everyone's best interest, no one lost customers to lower cost competitors and because regulators underwrote their costs.

The growth of more competitive wholesale electricity markets since FERC's 1996 Order 888 has created new challenges for reliability management. In the past, utilities generally owned both generators and transmission assets dedicated to serving customers in their exclusive franchise area. Now, generation and transmission are often owned by separate entities and neither bears sole responsibility for reliability problems. Franchises are no longer exclusive: wholesale customers can contract with whomever they want. Nor can regulators be counted on to underwrite idle assets, especially those benefiting customers in other states. Competition has also caused power to flow across system boundaries and vary in amounts not seen before. These new operating regimes have challenged engineers and system operators to develop new ways of ensuring reliable operations in an increasingly dynamic market environment.

The next section of this chapter discusses several reliability concepts and identifies some of the measures these definitions imply. Measuring reliability is akin to the problem of measuring good health. There is no good summary metric; there are a host of useful indicators. Competition and the August 14, 2003 blackout have highlighted the unstated role of information, computation and communications in traditional reliability concepts. Section 3 reviews some of the effects of markets on reliability planning and management and identifies additional reliability indicators. Section 4 reports the official reliability information. The chapter concludes with a discussion of how data gaps might be filled.

2. Reliability Definitions and Indicators

Federal interests in reliability focus on the interstate, high voltage power grid. State and local authorities have jurisdiction over the lower voltage distribution system and substantial say in the building and maintenance of the high voltage grid. Precisely where the high voltage grid ends and the low voltage distribution system begin is a matter of controversy. NERC's data and published analysis define the high voltage grid as 230kV and above. FERC's Form 715's reporting threshold for the high voltage grid is 100kV, but respondents generally include lines of 69kVand above. EIA's Form 412 defines the high voltage system as 132kV and above and the EIA Form 411 uses 230kV as the high voltage threshold. The differences matter because there are large areas of the country where 69kV and 138kV lines deliver wholesale, bulk power. Moreover limits on these lines may make it impossible to fully utilize much higher voltage transmission lines. For those reasons this report considers lines as small as 69kV.

When the demand for power (load) differs from generation net of losses, an alternating current system is unbalanced. If the difference is large enough the system will blackout-it will fail to operate in part or total. If demand exceeds net generation by a lesser amount voltage and frequency will drop, with possible damage to equipment. Likewise, net generation in excess of demand but short of failure will cause voltage and frequency to increase, again with possible damage to equipment. Any sustained imbalance will lead to large deviations in frequency and voltage.[4] Most equipment is designed to withstand only small departures from target voltage, frequency and power standards. Central control of how much power is injected and with drawn from the transmission grid is necessary to keep the lights on.

Operational control is mainly exercised at the level of the control area, ISO and NERC reliability region. In rare instances, such as in the case of the August 14 blackout, coordinated control across NERC regions up to the boundaries of the relevant interconnection may be needed to prevent blackouts. Federal oversight and data collection is focused on control areas and NERC regions.

Conceptually the frequencies of blackouts and brownouts, their duration, size and costs are fundamental measures of the grid's historical reliability. Prospective improvements in reliability could, in principal, be indicated by reduced probabilities of reliability problems and reductions in their expected duration, size and cost.

Economists argue the *level* of reliability should be set so that the marginal benefits of increased reliability (fewer outages, power quality lapses, reduced economic loss) would equal marginal costs (additional generation, transmission, or better system control). Utilities traditionally evaluated investments in emergency generation by comparing its cost with the cost of unserved energy. [5] The costs of unserved energy were those the utilities estimated on behalf of their customers together with the utility's own costs. At the level of an individual consumer, economists have defined reliability as the proportion of the time power of sufficient quality costs less than she is willing to pay. When marginal benefit from the consumer's perspective is less than marginal cost (the price of power), she does not consume, i.e., she chooses to black herself out.[6]

The U.S-Canada Task force defined reliability as

> 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 electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system Adequacy and Security.[7]

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[4] As mentioned in Chapter 2, the approximately 140 control areas in the United States are the basic unit for balancing power flows and maintaining power quality within their area.

[5] Schweppe, Fred et al, *Spot Pricing of Electricity*, Klur Academic Publishers, 1988, pages 137-145

[6] See, Chao, Hung-Po and Wilson, Robert, *Priority Service: Pricing, Investment, and Market Organization*, American Economic Review, Vol.77 No.5, December 1987, pages 899-916.

[7] Ibid, see Glossary.

Trends in experienced and expected frequencies of blackouts and substandard power quality would give policy makers quantitative grounds for concluding whether reliability is improving or deteriorating. For reasons discussed below neither the Federal Government nor NERC currently makes quantitative estimates of the future probabilities of blackouts and brownouts.

Instead of quantitative measures, the NERC uses a combination of expert judgment, quantitative modeling and scenario ("what if") analysis to assess qualitatively current and prospective reliability across and within regions.[8] NERC's qualitative evaluation hinges on two factors:

> "1. Adequacy-The ability of the electric system to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> 2. Security-The ability of the electric system to withstand sudden disruptions such as electric short circuits or unanticipated loss of system elements."[9]

NERC's focus is on whether physical resources within a NERC region, perhaps supplemented with emergency power imports, and operating practices are sufficient to maintain electrical balance under expected and emergency conditions. If they are, and there is a sufficient margin of safety, the system is judged reliable. This evaluation does not say how reliable the system is or whether additional investments would increase reliability or would be worth their cost.

Determining generator "adequacy" amounts to adding up the capacity of generators within the region, adjusting total capacity for maintenance and unplanned outages, and comparing the total with the sum of demand and losses less net imports. Likely and extreme values for outages, demand and losses are derived from historical data. Base (net) imports and emergency (incremental) imports appear to be derived from a combination of historical experience and modeling results. Since imports can replace the need for local generation, the selection of base imports is important to the generation adequacy assessment. If the comparison shows the amount of adjusted capacity exceeds that needed with a sufficient margin of safety, usually on the order of 15-20% of peak demand, generation is judged adequate. NERC does not document the basis for specific margins of safety.

Electrical models in particular power flow models of the regional power system are indispensable for determining whether the grid is "adequate" to deliver power where needed. The input data for these power flow models are extensive. The data include the impedance of all the branch lines in the transmission system, the topology—a statement of the connections between lines and buses--of the system, the limits of all the branches,

[8] NERC's summer, winter and multi-year assessments are available at their website www.nerc.com

[9] North American Electric Reliability Council, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America*, October 2002, page 7

the voltage control capabilities of the transformers, generator capacity and availability, and demands at individual buses. The results show the power flowing over all the different lines, its voltage and whether any limits, such as thermal limits on lines, are violated.[10] Engineers rely on power flow models to confirm that power flows under expected conditions do not exceed the grid's physical capabilities and operating limits.

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Text Box

Transmission Is Mysterious

1. Life in an AC network
    a. Electrons are not transported, shipped or otherwise moved from generators to consumers.
    b. Less is more and more is less- sometimes, depending
        i. Removing lines can increase delivery: increasing a line's capacity can decrease delivery.
        ii. Increasing consumption can relieve heavily loaded lines: decreasing consumption can overload lines.
    c. Lightly loaded lines often cannot carry more power.
    d. Fully loaded lines do not necessarily constrain delivery.
2. Why?
    a. Electrons in AC systems only move back and forth a small distance; they do not go from here to there.
    b. In a network there are multiple paths from generators to customers.* Electricity flows through a network along *all* possible paths following physical laws that favor those paths with "least resistance."
    c. There are no valves for directing electricity along secure routes.
    d. The entire system is limited by the weakest link
3. What that means
    a. Power flows, voltage and their control depend on the details of the network's physical configuration and on precisely how much is being generated and consumed at every location.
    b. Mathematical models are indispensable for sorting out the complexity and accurately showing how the network can meet customers' power demands.

* Electricity flows along more than one path (the scheduled, nominal, or dominant path) from a source to a load is called "Loop Flow."

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Engineers also need models of the region's connected neighbors to determine if base imports are feasible and whether additional (incremental) imports would be available to

[10] Thermal limits are imposed to prevent overheating of lines due to excessive power flows. An accessible discussion of kinds of line limits is contained in U.S.-Canada Power System Outage Task Force, *Interim Report: Causes of the August 14th Blackout in the United States and Canada*, November 2003, pages 5-6.

cover emergency imbalances. If power from all sources can be delivered with a sufficient margin of safety under the studied scenarios, then transmission is judged adequate.

Security analysis is concerned with the regional system's continued operation in the event of short circuits and equipment (generator and line) failures. Stability analysis aims at ensuring that voltage and system synchronization are kept within limits after a short circuit. Contingency analysis is concerned with reliable operation after generators and lines unexpectedly fail. The hypothetical events are called contingencies: the ensemble of events is called a contingency list.[11] These analyses result in limits on "the maximum amount of electricity that can be safely transferred over transmission lines".[12] These limits are imposed in adequacy analyses as if they were physical limits.

System operators in each control area enforce security limits by ordering generators within their systems to adjust their output, by disconnecting users and by restricting the flows of power into and out of their systems. Their actions are guided by real time metering data, computer models of their system and experienced judgment. Intersystem power flows are generally the result of specific scheduling agreements between system operators in adjoining areas. Managing power flows across control areas can be difficult simply because many parties must agree.

As documented in Section 4 below large blackouts and brownouts of the high voltage grid in the US are common but infrequent enough that statistically estimating regional probabilities and their trends is a dubious enterprise. Estimating future probabilities based on detailed electrical descriptions of regions, their experience of equipment failures and similar information is conceptually possible but expensive and of arguable accuracy.

Information relevant to indicating reliability as it relates to **transmission** would include:

1. Number, size, duration and cost of blackouts and brownouts.
2. Trends and Status of grid adequacy and security
    a. Peak demand, supply and power flows by control area
    b. Line outages
    c. Security limited lines, power curtailments and redispatch.
3. Planning Data
    a. Projected demand

11 In a contingency analysis, engineers present a power flow model of the electrical system with hypothetical demand conditions and a base case of operating generators and lines. Large generators and major lines are then taken off line one at a time to mimic unplanned outages. This is called an n-1 contingency analysis: all but 1 of the n pieces of major equipment in the electrical system is assumed to operate normally. The analysts note those operating regimes that cause failure of other large lines, potentially resulting in cascading blackouts. Through a planning procedure, they preclude catastrophic failures, essentially "outlawing" failed operating regimes, by de-rating vulnerable power lines. The line limits that are imposed to ensure that the system continues to operate after a failure are called n-1 limits, contingency limits, reliability limits or some similar term. If a major piece of equipment has already failed, the n-2 limits become the relevant constraints.

12 U.S.-Canada Power System Outage Task Force, *Interim Report: Causes of the August 14th Blackout in the United States and Canada*, November 2003, page 6.

   b. Projected generation and transmission assets
   c. Power transfer capabilities
4. Analytical tools
   a. Electrical models of regions, both as they currently exist and as described in planning documents.
   b. Contingency lists

3. Markets and Reliability

Interregional and regional wholesale markets have significantly impacted power line utilization and the volatility of power flows. NERC has noted that

> "The transmission system is being subjected to flows in magnitudes and directions that were not contemplated when they were designed and for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers…"[13] and
>
> "…operating experience shows that market conditions can, at times, cause volatile and unpredicted flow patterns that cannot be reliably accommodated by the transmission system."[14]

NERC has not, however, released the data and statistical analyses underlying these conclusions.

Operators require good interregional models, precise data, rapid computation and communications to successfully manage novel and increasingly volatile power flows.[15] The U.S.-Canada task force concluded that two of the three basic causes for the August 14 blackout relate to information technology; in particular, inadequate situational awareness and failure of reliability organizations to provide effective diagnostic support.[16] They also found that neither NERC nor the Federal Government maintained reference models of the directly affected regions and of the Eastern Interconnection.

Although everyone benefits from reliable service its costs are borne by specific generators and transmission owners. By bringing competition into generation and encouraging free trade across regional markets, FERC's restructuring has reopened the question of how to pay for reliability. Free-riding beneficiaries of costly investments have always been a feature of interconnected electrical systems. Under regulation, utilities were assured they would recoup their investments and they had no competitors to undercut their rates. Now their investments may advantage competitors and raise their own costs. Competitive generators cannot be faulted for resisting paying for idle or under-utilized assets that benefit everyone else.

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[13] NERC, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America*, October 2002, page 20

[14] NERC, 2003 Summer Assessment: Reliability of the Bulk Electricity Supply in North America, page 8

[15] Another alternative is to increase safety margins. That would require more investment in transmission assets and would lead to higher redispatch costs

[16] Op. cite, page 23.

State regulators also question why their state's citizens should pay for transmission investments that lower costs and improve reliability for outsiders. Regulators cannot be counted on to underwrite transmission investments, even those with significant local benefits. NERC notes that:

> "With industry restructuring and the development of regional wholesale markets, new transmission lines may be beneficial to all parties, including the consumers of electricity, but their costs are incurred by only one or several entities. As a result, those entities may be reluctant to build the needed transmission facilities."[17]

How to pay for reliability in a competitive environment is far from settled. The Northern ISOs have had some success using markets to provide mandated reserve generator capacity and various operating reserves. No one has demonstrated a market-based way of deciding the appropriate level of reliability and paying for it.[18]

To the extent that restructuring encourages demand response to prices (and distributed generation), markets may allow systems to operate reliably with smaller safety margins, reducing reserves of idle equipment. Numerous DOE studies have found price responsive demand can be as important for reliability as generation reserves: reducing demand is much like an increase in generation of the same amount and has the additional benefit of reducing line loadings.[19] Distributed generators can potentially supply power to the grid and meet a share of local demand, thereby directly relieving loaded lines.

Additional information relevant to assessing reliability in a market environment as it relates to transmission would include:

1. High quality, interconnection wide models
2. Actual investment in the high voltage grid including specific investments in instrumentation, communications, computation and control.
3. MWh metered to permit real time price responsive demand: MWh billed under real time pricing.

Credible interconnection models are necessary to manage reliability with increasing and novel interregional commercial power flows. Trends in investment in the high voltage grid together with information on who is paying for it would both compliment planning projections and would give policy makers a factual basis for re-considering how to pay for reliability investments. Investment data showing investment in instrumentation, computation and control would be consistent with operators gaining more control over the grid. Increased information and more precise control should allow for smaller safety margins in future reliability assessments. Price responsive demand would be one more

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[17] NERC, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America*, October 2002, page 28.

[18] Academic economists have proposed market mechanisms for determining reliability and paying for it. See, Chao, Hung-Po and Wilson, Robert, *Priority Service: Pricing, Investment, and Market Organization*, American Economic Review, Vol.77 No.5, December 1987, pages 899-916.

[19] Oak Ridge National Laboratory, *Load as a Reliability Resource in Restructured Electricity Markets*, ORNL/TM2001/97, June 1, 2002. See also, Goldman, Charles, Barbose,G., Eto, J., *California Customer Load Reductions during the Electricty Crisis: Did they Help to Keep the Lights On?*, Journal of Industry, Competition and Trade, 2:1/2, 113-142, 2002.

tool operators could use to balance demand and supply. That could make it possible for planners to reduce the need for reserve generation and new transmission facilities. EIA recently began collecting considerable information on distributed generation: there is no compelling reason to collect more at this time.

4. Official Reliability Data

Reliability incidents, outage probabilities and costs: Federal data on actual grid reliability is confined to the EIA –417, "Emergency Incident and Disturbance Report." The EIA-417 incident data has mainly been used as a starting point for grid security studies. This form must be submitted to DOE's Operations Center if one or more of the following apply:

1. Uncontrolled loss of 300 megawatts or more of firm system loads for more than 16 minutes from a single incident
2. Load shedding of 100 megawatts or more
3. System wide voltage reduction of 3% or more
4. Public appeals to reduce the use of electricity
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability
6. Actual or suspected cyber or communications attacks
7. Fuel supply emergencies
8. Loss of electric service to more than 50,000 customers for one hour or more
9. Complete operational failure or shutdown of the transmission end or distribution system.

The types of data that appear on the Form EIA-417 include information about the location, date, and time of the incident, as well as the nature of the disturbance. Also, information about the cause of the incident (if known) and the actions taken in response to the incident are requested.

To illustrate, Table 3-1 shows a list of some typical disturbances and unusual occurrences that were reported on the Form EIA-417 during the year 2002.

Table 3-1 Major Disturbances and Unusual Occurrences, 2002

Date	Utility/Power Pool (NERC Region)	Time	Area	Type of Disturbance	Loss (megawatts)	Number of Customers Affected	Restoration Time
January							
1/30/2002	Oklahoma Gas & Electric (SPP)	6:00 AM	Oklahoma	Ice Storm	500	1,881,134	2/7/2004 12:00
1/29/2002	Kansas City Power & Light (SPP)	Evening	Metropolitan Kansas City Area	Ice Storm	500-600	270,000	NA
1/30/2002	Missouri Public Service (SPP)	4:00 PM	Missouri	Ice Storm	210	95,000	2/10/2004 21:00
February							
2/27/2002	San Diego Gas & Electric (WSCC)	10:48 AM	California	Interruption of Firm Load	300	255,000	2/27/2004 11:35
March							

3/9/2002 Consumers Energy Co. (ECAR)	12:00 AM	Lower Peninsula of Michigan	Severe Weather	190	190,000	3/11/2004 12:00
April						
4/8/2002 Arizona Public Service (WSCC)	3:00 PM	Arizona	Vandalism/ Insulators	0	0	9-Apr
July						
7/9/2002 Pacific Gas & Electric (WSCC)	12:27 PM	California	Interruption of Firm Power	240	1 PG&E	7/9/2004 19:54
7/19/2002 Pacific Gas & Electric (WSCC)	11:51 AM	California	Interruption of Firm Power (Unit Tripped)	240	1 PG&E	7/19/2004 16:30
7/20/2002 Consolidated Edison Co. of New York (NPCC)	12:40 PM	New York	Fire	278	63,500	7/20/2004 20:12
August						
8/2/2002 Central Illinois Light Co. (MAIN)	12:43 PM	Illinois	Interruption of Firm Power	232	53,565	8/2/2004 18:36
8/9/2002 Lake Worth Utils (SERC)	8:23 AM	Florida	Interruption of Firm Power	51	25,000	8/9/2004 12:13
8/25/2002 Pacific Gas & Elec. (WSCC)	3:41 AM	California	Interruption of Firm Power	120	1 PG&E	8/25/2004 9:17
8/28/2002 Lakeworth Utils (SERC)	2:09 PM	Florida	Severe Weather	67.6	25,000	8/28/2004 15:38
October						
10/3/2002 Entergy Corporation (SPP)	3:33 AM	Coastal Areas of Southern Louisiana	Hurricane Lily	NA	242,910	10/4/2004 9:00
November						
11/6/2002 Pacific Gas & Electric Co. (WSCC)	10:00 PM	Northern and Central California	Winter Storm	270	939,000	Noon November 10
11/17/2002 Long Island Power Authority (NPPC)	3:48 PM	Northport, NY Norwalk, CT	Cable Tripped	0	0	Unknown
11/17/2002 Northeast Utilities (NPCC)	6:00 AM	Northwest and North Central Connecticut	Ice Storm	NA	224,912	11/21/2004 8:00
December						
12/3/2002 Entergy Corporation (SPP)	6:30 PM	Arkansas	Ice Storm	NA	43,000	12/5/2004 8:00
12/11/2002 Dominion-Virginia Power/North Carolina Power (SERC)	1:09 PM	Northern Virginia to Fredericksburg Staunton to Harrisonburg	Winter Storm	63	130,000	12/11/2004 13:45
12/14/2002 Pacific Gas & Electric (WSCC)	11:00 AM	Northern and Central California	Winter Storm	180	1.5 million	12/18/2004 16:00
12/19/2002 Pacific Gas & Electric (WSCC)	6:00 AM	Northern and Central California	Winter Storm	56	385,000	12/20/2004 17:00
12/25/2002 PPL Corporation (MAAC)	5:00 PM	Eastern Pennsylvania	Winter Storm	250	106,000	12/26/2004 5:00
12/25/2002 Metropolitan Edison Co./First Energy (MAAC)	10:00 AM	Reading, York, Hanover, Hamburg Pennsylvania	Winter Storm	NA	95,630	12/27/2004 8:30

Note: North American Electric Reliability Council region acronyms are defined in the glossary.

Source: Form EIA-417, "Electric Emergency Incident and Disturbance Report"

Seven of the reported twenty-three incidents were in the California and two were in Florida. Oklahoma experienced the largest blackout in terms of numbers of people affected. Assuming complete reporting of qualifying events, it is clear that major reliability failures are fairly common but spread around the country and involve a very small percent of delivered power nationwide. At the regional level of aggregation the historical data suggests that the frequency of failures is very low.

Outage probabilities. John Doyle of the California institute of Technology and others used NERC data to show outage frequencies for North America 1984-1997.[20] Figure 3-1 is an example of that body of research. Similar displays can be constructed from EIA data. Their work shows that the frequency of large outages is significant. The frequency of large outages follows a power law. That would imply the probability of outages does not vanish as its size increases: very large outages cannot be ruled out as a practical matter. There are, however, too few large outages to be confident that observed frequencies are accurate estimates of underlying probabilities at the regional level. Empirical estimates of changes in outage probabilities are of unknown accuracy for the same reason.

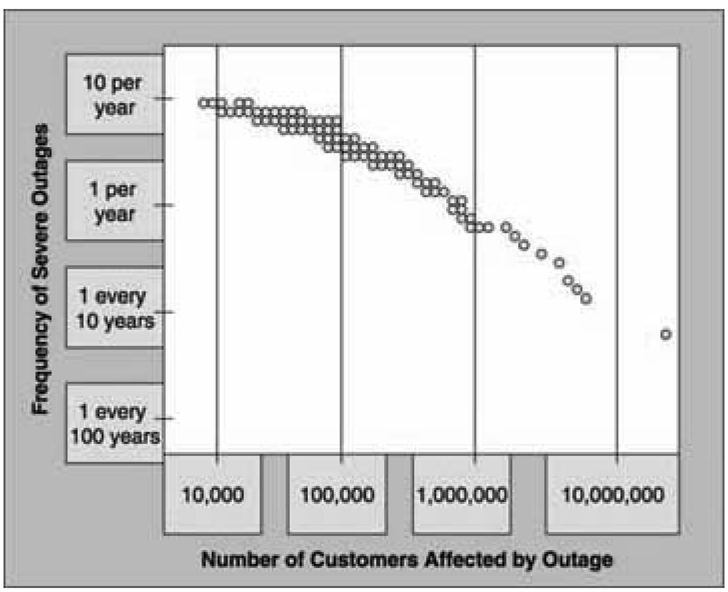

Figure 3-1. North American Power System Outages, 1984 – 1997

Source: Adapted from John Doyle, California Institute of Technology, "Complexity and Robustness," 1999. Data from NERC.

[20] See Carreras, Benjamin A., Newman, David E., Dobson, Ian, and Poole, A. Bruce, *Evidence of Self-Organized Criticality in a Time Series of Electric Power System Blackouts*, submitted to the IEEE Transactions CAS-1 May, 2002, available at Dobson@engr.wisc.edu

Costs. There are no official data on the cost of reliability incidents. The Federal government does not collect customer expenditures for backup generators, power quality protection, equipment damage and insurance. Consequently it is not possible to identify trends in actual losses or peoples' perception of the potential for loss.

The Electric Power Research Institute (EPRI), the insurance industry and researchers have attempted to compute annual costs due to power incidents. There efforts were not restricted to official data. Recent estimates of the annual national cost of blackouts and poor power quality range from about $20 billion to over $400 billion.[21] Researchers under contract to EPRI, however, concluded after an exhaustive review of the literature that

> There are few estimates of the aggregate cost of unreliable power to the U.S. economy. Documentation for existing estimates is either absent or based on assumptions that need additional review[22].

The lack of cost data makes vacuous policies, such as those followed by Electricite de France (EDF), to balance the costs of reliability investments against their cost savings.

Trends in Status of Grid Adequacy and Security: Since outage and power quality data do not support estimates of near term and regional reliability, it is natural for government oversight groups to examine data on recent and current conditions that bear on grid adequacy and security.

The FERC 714, the Annual Electric Control and Planning Area Report, is the major official source of recent data on reliability management. Control areas identify their interconnections with adjacent control areas and their scheduled and actual annual interchange (net power flows into and out of the area) in the context of showing the adequacy of their generation and transmission resources. Each control area collects monthly generating capability, net generation and net interchange for the reporting year. Importantly for reliability assessment, the form also records how the control area met the peak hourly demand occurring in each month.

FERC 714 is a double entry account, so that net transactions between adjacent control areas are reported directly. As control areas are associated wholly and uniquely with NERC regions, estimates of regional interchange could in principle be made by aggregating individual reports.[23] Unfortunately, discrepancies in reporting are significant. While many of the receipts and deliveries match exactly on both sides of the ledger, there are some modest differences in delivery and receiving area reports, possibly attributable to losses or differences in metering. More unsettling are gaps in reporting- one control area reports a delivery, but the named recipient does not report a receipt. The information

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[21] Eto, Joseph et al, Scoping Study on trends in the Economic Value of Electricity Reliability to the U.S. Economy, Lawrence Berkeley National Laboratory, LBNL-47911, June 2001. , page 14.

[22] Ibid. page x.

[23] "Dynamically-scheduled load" is not included in net interchange. Dynamic resources are sources, usually generators, located outside a region or control area whose output is dedicated to that control area. Since exchanges are explicitly balanced on the FERC 714, no distortion should be introduced by the exclusion.

on power flows between control areas is not sufficiently accurate, complete or at a high enough frequency to be useful in assessing the grid's ability to deliver power to control areas that need it, when they need it.

The EIA 411 collects somewhat similar information for NERC regions. The interchange information, however, is an annual total and does not identify power flows. That data are not useful for monitoring grid adequacy and security; their main use is for planning.

Line outages, both scheduled and unscheduled, obviously limit how operators can affect power flows but they do not necessarily limit the grid's ability to deliver power. An increase in outages over time complicates the task of delivering power and can point to underlying problems, such as neglected maintenance, which could eventually affect grid adequacy.

Data on transmission line availability are collected by the ten regional reliability councils and by many transmission-owning utilities. For example, the East Central Area Reliability (ECAR) region reported several interesting trends recently.[24] Availability of the 345 kV system in ECAR in 2001 was the second lowest in twenty years, primarily because scheduled outage time increased by 95 percent. The report notes that several of the longer outages in 2001 were attributable to work to connect independent generators to the grid.[25] The data are not reported in a standard form across NERC regions and is not readily available for lines of 69kV and above.

Increases or decreases in line loadings on a heavily loaded transmission path, corridor, or interface can indicate change in grid adequacy. During a time period when grid capability is fixed, increased transmission loading is a direct indication of reduced adequacy. The direction of these flows is usually well known at peak times, and the total corridor loading is equal to the sum of the loadings on a relatively small set of lines. Such data are maintained by NERC but are not publicly released.

A more direct measure of adequacy would be number of hours n-1, n-2 and higher level constraints are actually binding within a control area and region. It would be useful to know which lines are at a security limit, when the constraint became effective, how much power was curtailed and the cost of re-dispatching the system to meet demand. This information is generally not available.

One publicly available indicator of grid adequacy is NERC's Transmission Loading Relief (TLR) Database. The information is unique to the Eastern Interconnection. [26] This "Log" contains information on instances of transmission inadequacy at flow gates (major

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[24] ECAR, ***2001 Transmission Line Outages Summary Report*** (02-TFP-46), December 2002.
[25] Ibid, see p. 5.
[26] The Federal Energy Regulatory Commission has endorsed the use of transmission loading relief orders to individual generators to keep line flows below area interchange limits. These orders are based on a transaction's "priority" and not on its economic value. In addition, those generators who have a priority cannot sell it to others who are willing to pay. A summary of recent curtailments appears in Transmission Constraint Study, Presentation of FERC Staff to the Commission, December 19, 2001.

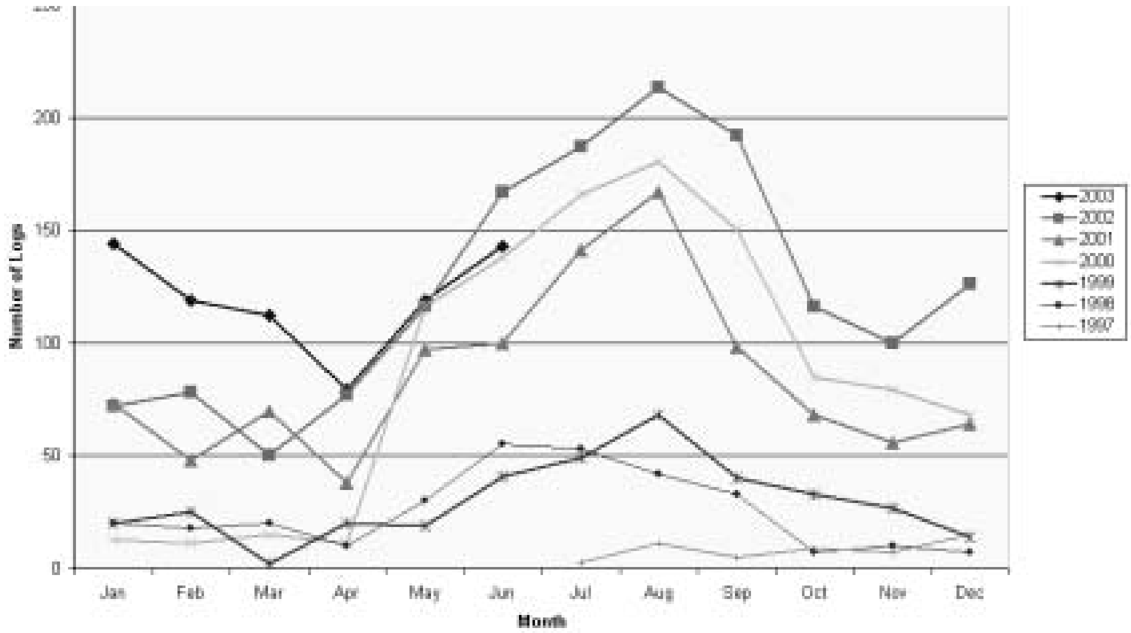
pieces of transmission equipment) and on major lines. In particular, it documents the requirement to implement NERC TLR procedures on specified days to protect major parts of the transmission system.[27] Similar information is not available for either the Western Interconnection or ERCOT. The Northern ISOs do not experience TLRs because they use prices rather than priorities to ration transmission resources.

There are nine TLR levels. Level "0" is normal operation, level 2 indicates that further increases would violate security limits and the higher levels all require curtailments. The curtailments start with low priority nonfirm point-to-point service and continue up to curtailments of firm point to point service. Figure 3-2 is a plot of TLR level 2 events by month of the year. Not surprisingly it shows TLRs increase significantly during the peak demand months of July and August.

Table 3-2. Level two or higher TLRs by Month

NERC does not report the volumes of power that are curtailed by TLRs. NERC did, however, provide that information to FERC staff writing the previously cited December, 2001, curtailment study.

[27] NERC's website (www.nerc.com) states "the NERC TLR procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservations priorities."



Planning Data. The starting point for establishing prospective adequacy is estimates of future demands, especially peak demand. The FERC 714 requires planning areas to report their actual hourly demand. Planning areas are also required to provide their forecasts of summer and winter peak demand ten years into the future. The historical data could provide a benchmark for projections as well as important data for modeling future demand.

NERC submits the EIA 411 on behalf of its 10 regional councils. The data includes five-year projections of supply and demand by NERC region. Supply means generation, but the form identifies existing transmission lines and proposed lines. The data can be used to indicate whether projected generation within a NERC region exceeds projected demand. However the form does not contain the kinds of information necessary to determine whether intra and interregional transmission is sufficient to deliver power where it is demanded under peak or other definable conditions.

The coverage and relevance of the data collected on the EIA 411 to NERC's short-term and long-term reliability assessments are unclear. The form is voluntary and may or may not include entities that are not members of NERC. The instructions do not require that the projects are consistent with those used in NERC's reliability assessments or with planning area projections contained on the FERC 714.

As mentioned in Section 2 of this chapter, NERC assesses power transfer capability between interconnected regions and sub-regions and publishes the "base" power transfers between regions and the incremental transfer capabilities in each direction. Such data provide a measure of the additional power that could be transferred from one region to a neighboring region, if the latter region experienced a sudden need for support. High levels of incremental capability indicate adequacy; low levels indicate potential for shortages to spread from one region to neighboring regions Table 3-2 gives the transfer limits from MAIN to MAPP, SERC and TVA under conditions NERC expected in the summers between 2000 and 2003.

Table 3-2. Base Transfers and Incremental Transfer Limits between Select NERC Reliability Regions and Subregions

From MAIN	To MAPP-US Base	To MAPP-US Incremental	To MAPP-US Inc / Base	To SERC TVA Base	To SERC TVA Incremental	To SERC TVA Inc / Base	To ECAR Base	To ECAR Incremental	To ECAR Inc / Base
2003	392	1000	255.10%	-28	2800	-10000.00%	905	3200	353.59%
2002	-214	950	-443.93%	172	2100	1220.93%	3	4000	133333.33%
2001	-214	950	-443.93%	-28	2300	-8214.29%	55	4000	7272.73%
2000	-235	1900	-808.51%	-388	3300	-850.52%	-61	4000	-6557.38%

Source: North American Electric Reliability Council, Summer Assessments 2000 - 2003

Generally the capabilities are substantial. However, the values are for non-simultaneous conditions, that is, these limits could not all be approached at the same moment. Further, the limits assume that all transmission facilities are in service, all facilities are loaded within normal ratings, and voltages are within normal limits.

The limits are also subject to supply and demand conditions that can cause base and incremental levels to change. Time series and econometric projections would be unlikely to anticipate the changes in base and incremental transfer capability shown in Table 3-2. The annual variations in base and incremental flows are sufficiently large that they can only be estimated with the help of models.

Analytical Tools: The planning data is one input to reliability assessments. In order to independently evaluate adequacy and security government officials and their experts require electrical models (power flow models) that accurately represent the relevant systems, whether control area, NERC region or interconnect.

The FERC Form 715, *Annual Transmission Planning and Evaluation Report*, is the major official source of the information required to build power flow models used to evaluate transmission adequacy and security.[28] Transmitting utilities that operate networks at or above 100 kilovolts, or their agents, submit the form to FERC annually. Normally NERC Regional Councils submit the Form 715 on behalf of their members. The required data includes:

1. Power flow base cases for its transmission system, or if the transmitting utility belongs to a regional or subregional transmission planning or reliability organization, power flow bases cases for that region or subregion;
2. System maps;
3. Descriptions of reliability criteria; and
4. Evaluations of the current and future performance of the transmission system.

The power flow cases are intended to be forward looking. FERC suggests that the cases include summer and winter peak conditions one, two and five to ten years in the future.

[28] This description is taken from the form's instructions which can be obtained at www.ferc.gov/docs-filing/eforms/form-715/instructions.asp

FERC also suggests that respondents include an analysis of light and heavy transfers one year in the future.

The EIA Form EIA-411, *Coordinated Bulk Power Supply Program Report*, requires power flow data similar to that provided in the Form 715 for newly planned transmission facilities.[29] Specifically, the Form 411 requires that respondents

> "… submit a single annual peak load power flow case that includes all prospective facilities to be energized in the next two years. Alternatively, the respondent may provide a copy of any annual peak load power flow case that includes the new facility for the year it is to be energized. If more than one facility is to be energized in a given year, it is acceptable to provide a single annual peak load power flow case that includes all the new facilities added in that year."

Neither the FERC nor the EIA power flow data are publicly available because of the Federal Government's concern with national security. The data are available for official government purposes, including policy analysis.

Neither the EIA 411 nor the FERC 714 require that the planning data control areas and NERC regions submit are consistent with the assumed facilities, grid configuration or demands assumed in the FERC 715 demonstration of reliability. It would not be a violation of reporting instructions for regions to submit EIA 411 and FERC 715 data that refer to significantly different visions of how reliability is to be achieved.

The utility of the FERC 715 is diminished by the uneven quality of reporting. In particular many of the submitted cases violate line loading and voltage limits. Contrary to specific instructions some respondents do not identify generators with EIA names, making it expensive to merge EIA and FERC data. Contingency lists are unavailable, though the instructions would seem to require them. And the information provided on service areas is not sufficient to locate demand centers (load buses).

The FERC 715 does not require power flow cases of the respondent's system as it currently exists; the data are for a hypothetical system that the respondent expects will exist in the future. This has two consequences. First it is not possible to use the 715 data to compare actual with calculated power flows as a means of validating the basic power flow model. Second, it is not possible to show how planned investments would provide for *additional* transmission capability and security of the existing system.

Because of the latitude respondents have for picking planning horizons, models of neighboring regions may refer to different years. That makes it difficult, if not impossible, to use the regional power flow models to confirm NERC's estimates of base and incremental transfer capacity. In fact, the cases do not specifically identify new transmission facilities; that information is available on the EIA Form 411.

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29 The Form EIA-412 for municipal, State, Federal and generation and transmission cooperatives requires reporting of existing and new lines. It does not require them to submit power flow cases.

The electrical models that can be constructed directly from this data only include the reporting area and some of the lines connecting it to outside areas. Most of the EIA-411 and FERC-715 data is at the NERC region level. In assessing reliability and security, imports from outside the reporting region can make the difference between normal operation and blackout. One way to bridge this information gap is with estimates of how much power can be brought into a region facing temporary shortages. That is what NERC does with its incremental transfer limits mentioned earlier.

Another way to account for the reliability consequences of imports and exports is to model the interconnections in their entirety. FERC does not require that be done. For many years NERC has sponsored committees to piece together their individual FERC 715 filings into a description of the Eastern and Western Interconnects. This is an arduous, error prone and expensive process. The resulting models, while useful, reflect the problems of joining electrical descriptions that reflect different assumptions, reference dates, aggregation conventions and nomenclature. Currently, there are limited tools for assessing reliability from a multi-region and interconnect wide perspective.

As demonstrated in the August 14, 2003 Eastern blackout, reliability problems cannot be managed or confined to a single utility, control area or NERC region. Preliminary analyses of the blackout's progress have repeatedly pointed to the fragmentary information available to system operators.[30] As the gird becomes increasingly integrated the need for interconnect spanning electrical models and supporting data will only grow.

Response to Markets: The growing importance of interregional power flows and regional markets requires tighter control over the grid than is customary in most of the country. High quality electrical models of the regions and the relevant interconnection are critical to achieving enough control to allow commercial flows with minimal arbitrary restrictions.

The incentives facing many market participants are to push the costs of reliability, information and system control on to others. That way they keep their costs low and can offer better terms than can "good citizens." Data on actual investment in the high voltage grid and information on how those investments were financed and who paid for them are necessary to quantify the extent of the free rider problem and to craft solutions. Investments in instrumentation, computation, communication and other elements of system control are particularly important. As discussed in Chapter 4, the FERC Form 1 reports more aggregate investments and does not sharply separate distribution from high voltage transmission.

The advent of real time pricing would make it possible for customers to respond to prices. As discussed in Chapter 6 there is little data on how much load is currently metered to allow real time pricing or of the amount of power that is being sold at real time rates.

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[30] See for example, Lipton, Eric, Perez-Pena,R. and Wald, M., *Overseers Missed Big Picture as Failures Led to Blackout*, New York Times (National), Vol.CL11….No. 52,605, September 13, 2003, pages A1 and A10.

5. Filling the Information Gaps

In a regulated, cost-of-service world each utility could reasonably be held accountable for reliable service within its exclusive service area. Transmission was secondary to generation; it was cheap by comparison and utilities simply built lines as needed to serve their customers. With restructuring some utilities have divested generation and all are seeing power flowing across utility and regional boundaries in response to commercial opportunities. That together with the entry of independent generators supplying local and distant markets, means reliability is increasingly dependent on building and managing transmission.

Data collections that the government relies on to monitor reliability have not kept pace with the ascendancy of transmission in a restructuring industry. The government does not have the power flow models necessary to verify the efficacy of the industry's reliability plans as they relate to transmission within a region. The industry's reported plans are not necessarily those imperfectly analyzed in the power flow analyses that industry does submit to FERC. Data for monitoring investments in the high voltage grid, including those to improve grid control, and indicators of reliability trends are not routinely available to government. Neither the industry nor the government has data adequate to allow rigorous cost-benefit analyses of transmission related investments to enhance reliability.

Much improvement in the government's capability to oversee reliability could be achieved without new data collections. Instead, were FERC to modify the FERC 715 and rigorously monitor the quality of responses, government engineers could construct the power flow models necessary to confirm current reliability and to examine the efficacy of reliability plans. The FERC 715 power flow models frequently show electrical violations, reporting errors, and do not necessarily describe the existing grid. The government's oversight would be enhanced if the planning regimes described in the FERC 714 and EIA 411 and 860 were among the cases evaluated in the FERC 715. FERC and EIA could accomplish that by first requiring the planning data on the FERC 714, EIA 411 and EIA 860 to describe the same "plan".[31] Then FERC could, for example, require that the FERC 715 power flows show how well the plan provides for "adequacy" and "security" one year, three years and five years into the future.

Table 3-3 exhibits many of the specific changes that would be required to existing FERC and EIA forms.

Table 3-3. Modify Existing Data Collections

Information Need	Form	Needed Changes	Comment

[31]The EIA 860 does require that identified planned power plants and generators be taken from "planning data." Planning data is not defined on the form.

1.High quality power flow models	FERC 715	1.Identify load buses by MSA.[32] 2. Power flow cases of existing system. 3. Model planning data for 1, 3 and 5 years in future. 4.Provide contingency lists 5. Explain line and voltage violations	The quality of reporting is often poor. Submissions often do not use EIA/EPA names and contain serious electrical violations
2. Data on the recent adequacy, security status of control areas. Data to verify power flow models of existing system.	FERC 714	1. Actual hourly demand, generation, inter-control area power flows experienced in control regions for 715 cases (2 above) 2. Experienced line and voltage violations. 3.Use EIA/EPA generator names and same line/bus identifiers as on the FERC 715	
3. A consistent set of reference reliability plans.	FERC 714, EIA 411 and EIA 860	1. Require EIA 411 and 860 data to describe the same plan 2. Require FERC 714 (Part 111, Schedule 2. and EIA 411 demand projections are consistent.	These plans should be the basis for the power flow analyses 1, 3 and 5 years into the future.
4. Monitor Demand Response	EIA 861	Add a schedule showing total MWh metered hourly (or higher frequency) and number of MWh billed by time of consumption	To quantity extent of price responsive demand. See chapter 6.

[32] MSA stands for Metropolitan Statistical area. An MSA is a geographic entity defined by the U.S. Office of Management and Budget. Qualification of an MSA requires the presence of a city with 50,000 or more inhabitants, or the presence of an Urbanized Area (UA) and a total population of at least 100,000 (75,000 in New England).

5. Quantify investment in the high voltage grid and in its metering and control	FERC 1	1. Adopt NIA definition of investment. 2. Report line and associated equipment investment by voltage level. 3. Report investment in metering, communication, software and control of the high voltage grid	See chapter 4.

At such time as reference power flow models are available for regions it would be appropriate for the Federal government and NERC to build interconnection wide models.

The government's ability to monitor trends in reliability could be substantially improved were NERC and FERC to build a time series data base on security limits experienced on high voltage lines and flowgates, curtailments, denied service and power flows across the 230kV and above grid.   That would require a formal agreement between FERC and NERC.

Finally, data on the costs of blackouts and substandard power quality, including what people spend to protect themselves, would be useful. Given the other needs that data are of relatively low immediate priority.