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Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis

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Preface

Section 205(a)(2) of the Department of Energy Organization Act (Public Law 95-91) requires that the Administrator of the Energy Information Administration (EIA) carry out a comprehensive program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. This report was written in view of those responsibilities. Federal law prohibits EIA from advocating policy.

Douglas R. Hale (DHale@eia.doe.gov, 202 287-1801) was the project leader for this study and the principal author of the report. Thomas Leckey conducted much of the research on data describing the grid's support of markets. He also performed important research on the data and models relevant to reliability. Matthew Lackey researched and compiled much of the financial and demand data contained in this report. Emily Bartholomew of Lawrence Berkeley National Laboratory (LBNL) constructed the graphics and most of the tables appearing in this report. LBNL staff and senior management, particularly, Joseph Eto and Mark Levine, contributed expertise and critical research resources to this project.

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In addition, a number of individuals took it upon themselves to provide critical reviews of major sections of the report. Among those volunteers are John Kelly (American Public Power Association), Robert Thomas (Cornell University), Bernard Lesieutre and Joseph Eto (LBNL), Udi Helman and Thanh Luong (Federal Energy Regulatory Commission), and David Meyer (U.S. Department of Energy). EIA reviewers included Rodney Dunn, Patrick Farace, Nancy Kirkendall, Kevin Lillis, Larry Spancake, Phillip Tseng, Louis Demouy, Stan Kaplan, and Susan Holte. Collectively they performed the invaluable but thankless jobs of correcting errors of fact and logic, identifying relevant data series, and suggesting alternative interpretations of the facts uncovered in the course of the research. The author is indebted to them all.

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Introduction

Federal law and implementing regulations are causing the most significant change in the U.S. electric power industry since the Great Depression. For more than 60 years the industry was characterized by a structure—utilities serving exclusive franchises—and a regulatory strategy—pricing at average prudent cost of service—that are now changing in fundamental ways.

Beginning with the Public Utility Regulatory Policies Act of 1978 (PURPA), and continuing with the Energy Policy Act of 1992 (EPACT), Congress allowed certain kinds of generators to enter wholesale power markets. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888 requiring:

> *. . . all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service . . . .*[1]

The Order "unbundled" electrical energy generation from transmission and other services needed to deliver power to customers.[2]

FERC's intent was that its own administrative determination of the cost of service would eventually be replaced by competitive markets as the arbiter of just and reasonable rates for wholesale energy and any services that could be supplied competitively. As FERC explained, Order 888 is necessary because:

> *The only way to effectuate competitive markets and remedy discrimination is through readily available, non-discriminatory transmission access.*[3]

Transmission, however, would remain regulated.[4] An exception is that the rates charged by "merchant" transmission projects would not be regulated.[5] Efforts by FERC and the States to bring competition to the electric power industry are collectively referred to as restructuring. In response to Order 888 and other FERC initiatives, the industry has seen a huge increase in the number of independent generators seeking transmission services.

Recently the U.S. Department of Energy (DOE), FERC, and the U.S. Congress have questioned whether the high-voltage transmission system is capable of supporting its growing economic role.[6] In May 2001, the National Energy Policy Development (NEPD) Group, referring to the transmission system as the "highway system for interstate commerce in electricity," recommended that reliability standards be made mandatory, in part because of the increasingly competitive nature of the electricity market.[7]

In May 2002, DOE's National Transmission Grid Study called attention to the physical capability of the transmission infrastructure by finding:

[1]Federal Energy Regulatory Commission, "Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Order No. 888, Final Rule (April 24, 1996), Summary.

[2]Order 888 also identified a number of ancillary services that were considered, from a regulatory point of view, to be part of transmission service and thus subject to regulatory oversight and the potential for market pricing. These ancillary services include voltage regulation, operating reserves, and balancing energy. The companion Order 889 required transmission providers to post their available transmission capability (ATC) on Internet sites, collectively called the Open Access Same-Time Information System (OASIS).

[3]Federal Energy Regulatory Commission, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Order No. 888-A, Docket Nos. RM95-8-001 and RM94-7-002 (March 4, 1997), p. 11.

[4]The high-voltage transmission grid is almost universally viewed as a natural monopoly. Without a grid operator to balance power supply and demand at all times, maintain voltage, and ensure that lines are not overloaded, the grid could not operate. The operator accomplishes this by such means as requiring generators to adjust their output to protect the system, opening and closing circuits, and limiting net imports. The grid operator, therefore, has enormous influence over the availability and price of transmission. This power is neither tempered by competition from other networks nor influenced by the threat that most users might leave the grid. Consequently, transmission is regulated virtually everywhere.

[5]A merchant transmission firm directly charges users of its lines for their use. It does not recover its fixed costs through regulated rates.

[6]In 2002 the high-voltage electrical grid consisted of more than 157,000 miles of high-voltage power lines (230 kilovolts and above) connecting generators to bulk power consumers (North American Electric Reliability Council, *Reliability Assessment 2002-2011*, October 2002, Table 3, p. 22). At times government and industry define high-voltage lines as starting at 69 or 138 kilovolts. Bulk power customers include large industrial and commercial facilities, governments, cooperatives, traders, and distribution companies that buy power at wholesale. Distribution companies supply mostly retail customers at low voltage.

[7]U.S. Department of Energy, National Energy Policy Development Group, *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (Washington, DC, May 2001).

There is growing evidence that the U.S. transmission system is in urgent need of modernization. The system has become congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities . . . .[8]

Similarly, in July 2002 FERC called attention to both transmission infrastructure and markets in concluding:

[There are] . . . persistent and costly problems in the nation's wholesale electric power markets. These include a decade of under-investment in needed transmission, generation siting in locations far from customers, unduly discriminatory behavior by transmission providers . . . and fundamental design flaws in certain existing electricity markets . . . .[9]

Less well recognized is the impact of the industry's structural change on the data supporting public policy. When there is a fundamental change in the way an industry does business, as is now happening in electricity, the basic data needed to describe the industry also change. Federal agencies charged with collecting industry data may need to modify their data collection methods and, as needed, acquire new kinds of data. The agencies must also develop new ways of aggregating and disaggregating basic reports to accommodate new organizational and market boundaries.

The Federal Energy Administration Act of 1974 (P.L. 93-275, 15 U.S.C. 761 et seq.) and the DOE Organization Act (P.L. 95-91, 42 U.S.C. 7101 et seq.) require the Energy Information Administration (EIA) to carry out a centralized, comprehensive, and unified energy information program to collect, evaluate, assemble, analyze, and disseminate information on energy resource reserves, production, demand, technology, and related economic and statistical information for use in assessing the adequacy of energy resources to meet near-term and longer term domestic demands and to inform public policymakers. FERC is responsible for regulating the wholesale power market and the high-voltage transmission system that supports interstate trade. Together, FERC and EIA are the major Federal Government sources of transmission information.

The changing structure of the industry and the Federal Government's increasing interest in transmission have prompted EIA to reexamine current official data collections to determine whether they continue to meet the needs of the Government.[10]

Purpose of This Report

One purpose of this report is to examine how well existing official data serve the function of informing Federal policymakers about electric power transmission in interstate commerce. Official data are those produced by the Federal and State governments, their agents, and regulated entities such as Independent System Operators (ISOs). Data that are *routinely* supplied to DOE, EIA, and FERC by the North American Electric Reliability Council (NERC) are also included.

A second purpose of this report is to determine whether currently unavailable data could in fact be obtained. Before any agency of the Federal Government can collect or continue to collect data from 10 or more persons, it must obtain approval from the Office of Management and Budget (OMB). Two minimum thresholds for OMB approval of an agency's data collection are that the data are needed for the Federal Government's legitimate purposes, and that the data can in fact be obtained. Those thresholds are the focus of this report.

Regarding OMB's first threshold, the Federal Government needs data and models to answer factual questions basic to resolving long-standing public policy issues. This report identifies transmission information relevant to three broad national policy interests:

- Reliability[11] and national security
- Economic regulation
- Economic growth and efficiency.[12]

The Federal Government's role in reliability management has been to monitor outages and require investor-owned utilities (IOUs) to show that their plans are

[8]U.S. Department of Energy, *National Transmission Grid Study* (Washington, DC, May 2002), p. xi.

[9]Federal Energy Regulatory Commission, "Commission Proposes New Foundation for Bulk Power Markets With Clear, Standardized Rules and Vigilant Oversight," News Release (July 31, 2002), Docket No. RM01-12-000.

[10]EIA has also sponsored focus groups of data suppliers and users to determine their needs and constraints in supplying transmission data.

[11]Reliability is defined here 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. For more discussion on the concept of reliability, see Chapter 2.

[12]The East Coast blackout of 1965 and subsequent blackouts in the western United States, the terrorist attacks of September 11, 2001, and the August 14, 2003, East Coast blackout showed the national interest in a reliable, secure transmission grid. The Federal Government's substantial involvement in regulating and in building interstate power transmission and generation goes back to the start of the New Deal. The Federal Power Act of 1935 authorized the Federal Power Commission (now FERC) to regulate utilities involved in interstate transmission and power sales to ensure "just and reasonable" electricity prices. In 1933, the Federal Government chartered the Tennessee Valley Authority to build hydroelectric facilities to promote regional economic development.

consistent with reliable operations.[13] DOE also sponsors reliability research, conducts investigations after major outages, and works with industry reliability groups to anticipate reliability problems.[14] 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, NERC.

Since the September 11, 2001, terrorist attacks, the Federal Government has restricted access to certain grid data that were previously available to the 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 requirements will only grow.

FERC is charged with ensuring just and reasonable prices for power in interstate commerce. In addition, State regulators continue to be deeply involved in transmission regulation. They effectively regulate transmission costs and prices for "internal transactions" and also control siting and eminent domain.

FERC has long collected data on capital and operating costs from IOUs. FERC uses the information to ensure that tariffs for wholesale electricity sales bear a reasonable relation to costs. EIA complements the FERC collections with less detailed reports from other generation and transmission owners to produce industry-wide totals.

For almost a decade FERC has been attempting to create competitive wholesale electricity markets by opening the Nation's electricity transmission grid to competing generators, by promoting regional transmission markets, and by encouraging investment in transmission capability.[15] If its policy initiatives succeed, FERC would transform large areas of the country into "common markets" for electricity commerce. The transmission grid would become a network of superhighways for markets, seamlessly moving power across the country to reduce costs and improve reliability. FERC would then be in a position to use markets as the primary means of deciding whether wholesale prices are "just and reasonable."

The Federal Government is also responsible for approving utility mergers and for enforcing antitrust law, as well as wire fraud and conspiracy statutes incident to recent prosecutions for electricity market manipulation.

The data examined in this report are those needed to address factual questions of policy interest, including the following:

- How reliable is the grid? Is reliability improving or deteriorating?
- How much does transmission cost? What are the revenues, prices, and returns of transmission? How do costs, prices, and returns compare regionally?
- What investments are being made to expand, maintain, and modernize the grid?
- Is the grid accommodating economic trade? Is the grid available to all competitors (i.e., is there open access)? How much do customers and generators pay for transmission? What is the quality of transmission service?
- Are markets for wholesale electricity competitive? Is the grid being used to shield firms from competition?

Regarding OMB's second threshold, this report indicates that currently unmet data needs might be satisfied by one of three means: by modifying existing data collections, by coordinating and consolidating information from official and quasi-official entities, or by undertaking new data collections. It shows that, in principle, the needed data can be obtained; however, the suggestions do not represent the only or necessarily the best ways of obtaining transmission data.

Any significant change in official transmission data would require long-term coordinated effort across EIA, FERC, DOE, and OMB. In reviewing any specific proposal, OMB would consider more than the policy relevance of the data and whether it could be collected. (For example, EIA's fiscal year 2005 budget does not include funding for the Form EIA-412 survey, which collects

[13]Form EIA-417 collects data on outages and power quality problems. Form EIA-411 and FERC Form 715 collect facility and electrical data needed for reliability studies.

[14]DOE plays a major role in investigating large-area reliability failures, as discussed in Chapter 3. See, for example, U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), web site https://reports.energy.gov/BlackoutFinal-Web.pdf. The Department's Office of Electricity Transmission and Distribution also sponsors a wide-ranging program of research into technologies to improve reliability and better manage the grid. See web site http://electricity.doe.gov.

[15]See Federal Energy Regulatory Commission, *Promoting Wholesale Competition through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, Final Rule, 18 CFR Parts 35 and 385 (April 24, 1996); *Regional Transmission Organizations*, Order No. 2000, Final Rule, 18 CFR Part 35 (January 6, 2000); *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. RM01-12-000 (Washington, DC, July 31, 2002); and *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. PL03-1-000 (Washington, DC, January 15, 2003).

data from public power and municipal systems, including transmission-related information.) OMB would also consider public comments, whether the data are available elsewhere, the likely quality of the data, the cost of collection, the burden on the public, and whether the data should be confidential. Those issues are not considered in this report.[16] This report, therefore, neither advocates nor commits the Federal Government to the collection of specific data elements in the future.

Transmission Data and Industry Restructuring

Official data collections were designed in the context of electricity markets based on cost of service, dominated by utilities that served exclusive franchises. Relative to generation, transmission was cheap. Utilities built whatever transmission they needed to serve their customers, and few relied on power from distant suppliers to meet their customers' needs. In that world, transmission was not a focus of policy attention.

The Federal Government collects a great deal of information about transmission, much of which is predicated on an industrial structure that no longer exists. Many gaps in transmission data discussed in this report have come about because restructuring is changing the structure of the electric power industry.

For the limited purposes of this report, the basic elements of a restructured market can be characterized as follows:

- Energy, reserves, transmission and various services are unbundled and separately priced. Transmission is to be a standalone enterprise.
- The grid and wholesale markets are open to competitors.
- Markets are used to price wholesale energy and, when possible, related services.
- Transmission tariffs are regional, based on regional capital recovery and operating costs.
- Additional charges associated with using fully loaded lines—i.e., congestion charges—provide signals for transmission use, generator siting, and grid expansion. Congestion charges are based on market prices.[17]
- Grid expansion projects are based on regional plans.

The scope and pace of restructuring have been uneven across the United States, and as yet no part of the country is "fully restructured." Currently, industry participants operate in one of three distinct economic and regulatory systems:

- ISOs in the Northeast and California are operating restructured public markets under formal agreements with FERC, but each ISO has taken a different approach to restructuring.
- Public power systems, cooperatives, municipal systems, and most of Texas (ERCOT) operate outside of FERC jurisdiction in most respects. In Texas, ERCOT operates its own market.
- The remainder of the industry is operating in FERC-regulated, private markets that have not been restructured.

In much of the country electricity is unbundled, the grid is at least partially open to competitors, and markets are being used to price wholesale energy. Except for the Midwest ISO, the ISOs have auction markets with publicly reported wholesale market prices. They differ in their operating procedures and the details of their markets. The majority of the country, however, depends on bilateral agreements made in private markets, and wholesale prices are not public. In most of the country transmission rates are not regional, there are no separate congestion charges, and regional planning is limited.

Findings

Reliability

With restructuring, some electric utilities have divested generation. All are seeing power flow across utility and regional boundaries in response to commercial opportunities. That development, together with the entry of independent generators supplying local and distant markets, means reliability is increasingly dependent on the building of new transmission capability and the management of existing capability across expanding areas.

Data collections that the Federal 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 electrical models (power flow models) and data necessary to verify that existing and planned transmission capability is adequate to keep the lights on. The industry's reported plans for assuring

[16] The availability and quality of privately collected data vary over time, depending to some extent on what official sources choose to collect and release. Data quality, costs, burden, confidentiality, and similar attributes can only be evaluated relative to a specific collection proposal at a particular time.

[17] Congestion costs and revenues and system redispatch costs all arise from limits on the transmission grid. They are discussed in Chapter 4.

reliable operation in the future are not necessarily those analyzed in the power flow analyses that industry does submit to FERC. Investment in the high-voltage grid for metering, monitoring, communications, software, and computation is unknown. 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 ability to oversee reliability could be achieved by modifying existing data collections, as shown in Table O1. The forms referenced in Table O1 are described in Chapter 1.

Financial Performance and Investment

FERC collects capital and operating cost data from IOUs as part of its responsibility to ensure just and reasonable electricity prices. EIA and the U.S. Department of Agriculture's Rural Utilities Service (RUS) complement the FERC collections with less detailed reports from the other generation and transmission owners to produce industry-wide totals. FERC's Commissioners are concerned with the economics of transmission as a standalone enterprise because of their obligation to ensure just and reasonable prices in a restructuring environment. But FERC's financial accounts are more appropriate to the circumstances of integrated regulated utilities selling bundled electricity in a cost-of-service environment.

Apart from a few "transmission only" entities, FERC Form 1 says little about the economics of transmission. Official data do not capture transmission's financial performance, in large part because most transmission revenue is bundled with revenue from retail sales and is not separately identifiable.

If transmission were fully unbundled, its revenues would be unambiguous. Absent that, FERC could require line-of-business reporting—a fundamental change that would be tantamount to introducing a new data collection form. How useful or valid the resulting estimates would be is a serious question.

Far less dramatic changes to FERC Form 1, Form EIA-412, and Form EIA-860 would make the data more useful for cost and investment (but not financial) analysis. Precise definitions of transmission would be a logical place to start. The available data describing transmission operation costs, capital stock, and investment are not comparable across reporters, because neither FERC Form 1 nor Form EIA-412 imposes a common definition separating transmission from distribution.

The "investment" series derived from official data are flawed in at least three other ways. First, additions to transmission plant and equipment reflect not only new investment but also purchases of existing assets from others, land purchases, and other expenditures that, while relevant for some purposes, are not "investment"

Table O1. Reliability Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. High-quality power flow models of existing and planned systems.	FERC 715	1. Identify load buses by MSA.[a] 2. Add selected 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 uneven. 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 selected 715 cases (2 above). 2. Experienced line and voltage violations. 3. Use EIA/EPA generator names and same line/bus identifiers as on FERC Form 715.	
3. A consistent set of reference reliability plans.	FERC 714, EIA-411, EIA-860	1. Require Forms EIA-411 and EIA-860 data to describe the same plan. 2. Require FERC Form 714 (Part 111, Schedule 2) and Form EIA-411 demand projections to be consistent.	These plans should be the basis for the power flow analyses 1, 3, and 5 years into the future.
4. Monitor potential demand response.	EIA-861	Add a schedule showing annual total megawatthours metered hourly (or higher frequency) and megawatthours billed by time of consumption.	To quantify extent of price responsive demand (see Chapter 5).
5. Investment in metering and control of the high-voltage grid .	FERC 1, EIA-412	1. Adopt NIPA definition of investment. 2. Report investment in metering, communication, software, and control of the high-voltage grid.	See Chapter 2.

[a]MSA stands for Metropolitan Statistical Area. An MSA is a geographic entity defined by the U.S. Office of Management and Budget. Qualification as 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).

in the sense of the National Income and Product Accounts (NIPA).[18] The EIA forms that are modeled after FERC Form 1 share those attributes. Second, EIA, unlike FERC, collects financial data on a fiscal year basis rather than a calendar year basis. Consequently, EIA and FERC investment and other financial data cannot be added to arrive at a valid national total. Third, official data do not appear to capture investment in the grid by new market participants: merchant transmission companies and independent power producers.

Official financial statistics are not informative about transmission revenues and costs, such as ancillary service and redispatch costs, that restructuring makes visible in prices. As ISOs and Regional Transmission Organizations (RTOs) become more prominent, it will be increasingly important to allocate transmission costs to particular organizations. The kinds of changes to existing forms that would be required are shown in Table O2.

Transmission and Wholesale Power Markets

Much of the data needed to evaluate the grid's support of markets is already being collected. EIA collects comprehensive data on generators, including those planning to connect to the grid. Those data are indispensable for analyzing the potential supply of electricity and the entry of generators to the market, and for calculating market shares. FERC's Open Access Same-Time Information System (OASIS) contains data critical to evaluating access, transmission tariffs, and the quality of service. NERC has data on power flows across the high-voltage grid and on curtailments of transmission service. The ISOs are reporting congestion.

The data are not, however, available for policy analyses. NERC's power flow and curtailment data are not routinely available for use in assessing how transmission constraints affect wholesale power markets. Consolidating, editing, and archiving in a single database all the data that are required to be on individual OASIS sites would substantially improve the Government's ability to evaluate the progress of restructuring, as shown in Table O3.

Outside the ISOs, spot market prices and associated quantities, including interregional trade flows, are not available. FERC's new Electric Quarterly Report (EQR) does record transaction prices and quantities for "long term" and "short term" transactions, but they are not the same as the spot market prices reported by the ISOs. It is too early to know whether the EQR data can yield accurate estimates of market prices comparable to those in the ISOs. If not, a new collection would be required to obtain wholesale prices and associated quantities. Significant research and effort would be required in order to collect the information. DOE and the Canadian government both report annual volumes of trade flows

Table O2. Financial and Investment Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. Consistent separation of transmission from distribution accounts.	FERC 1, EIA-412	Explicitly define transmission in the same way for all utilities and use that definition in assigning costs, revenues, and net capital.	Current data are an "apples and oranges" mix.
2. Utility investment in the high-voltage grid.	FERC 1, EIA-412	1. Adopt NIPA 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.	Current "additions to plant and equipment" data have very limited use for economic and reliability analysis, although they are important to capital cost recovery.
3. Independent power producer (IPP) investment.	EIA-860	Collect direct connection and grid reinforcement costs from IPPs on EIA 860.	Some of these investments may not be picked up on FERC Form 1. See Chapters 3 and 4.
4. Merchant transmission investment.	EIA-412	Add to the list of respondents and require them to report transmission investments, as defined above, and to fill out Schedules 10 and 11.	Merchant investment and line data are not currently collected.
5. Ancillary service revenues.	FERC 1, EIA-412	Require reporting as proposed by FERC.	
6. Re-dispatch costs.	FERC 1, EIA-412	Require reporting.	Only applicable to utilities owning generators. Not necessary for ISOs.
7. Regional costs.	FERC 1, EIA-412	Require reporters to disaggregate cost, revenue, net capital stock, and investment by appropriate region.	This would allow regional cost comparisons.
8. Consistent aggregation.	EIA-412	Adopt FERC definitions (see above) and require reporting by calendar year.	EIA currently allows reporting by fiscal year.

[18]The National Income and Product Accounts, maintained by the Bureau of Economic Analysis, U.S. Department of Commerce, provide an aggregate view of the final uses of the Nation's output and the income derived from its production. For more information see web site www.bea.doc.gov.

between the United States and Canada. Estimated net volumes differ by about 10 percent, and the directions of year-to-year changes in net flows sometimes differ. EIA and DOE are working to resolve the differences.

Wholesale Competition

The ISOs have all the data needed to assess competition within their areas, but outside the ISOs the Government does not have the data necessary to monitor and evaluate the competitive status of wholesale markets. Government can subpoena data in response to clear evidence of anticompetitive behavior or as part of a merger approval, but the subpoena is not a reasonable means of obtaining data for ongoing market monitoring.

If Federal regulators and antitrust officials are satisfied with market share analyses, then the critical need is for high-quality power flow models to delineate market boundaries. That could be accomplished with power flow models developed for evaluating industry's reliability plans. If Federal regulators and antitrust officials require analyses of cost-price ratios (Lerner indices) for non-ISO areas, price/quantity data, and other currently unavailable data would be needed.

Conclusion

As markets for energy develop, the grid's economics and operations are becoming more integrated. Prices, supplies, and reliability are not as closely associated with individual firms as in the past. Neither power flows nor markets begin and end at ownership and jurisdictional borders, and even if they did, individual companies and system operators rarely have complete information on topics of policy interest. Federal and State policymakers are forced to look beyond individual company reports and political boundaries to inform their oversight of the grid.

Changing and consolidating existing data collections could greatly enhance the data available to Federal and State policymakers. As mentioned above, the changes would require long-term, coordinated effort across FERC, EIA, DOE, OMB, ISOs, and perhaps NERC.

New collections would be useful to describe wholesale prices and trade flows, congestion, regional costs and revenues, and interconnection-wide reliability management. However, the reality is that new collections often are controversial and have long gestations.

Report Organization

This report is organized in five chapters. Chapter 1 enumerates and describes current Federal transmission data collection and identifies some of the data elements available from NERC and the ISOs. The other chapters review information that can be used for describing and analyzing transmission as it relates to reliability, regulation, and economic growth.

Chapter 2 begins by noting that the Federal Government's role in reliability management has been to monitor outages and require IOUs to show that their plans are consistent with reliable operations. The Government requires data to identify reliability trends and emerging problems. The complexity of electricity transmission's role in reliability means that electrical models are necessary to interpret the reliability consequences of trends revealed in the data and of changes in the grid's configuration. Because data series alone can say very little about reliability, policy analysis and formulation are particularly challenging.

Table O3. Transmission and Wholesale Power Market Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. Access time series data by provider.	OASIS	Consolidate, edit, and archive all data required on OASIS in a single database.	
2. Transmission service offerings and actual rates.	OASIS	As above.	
3. Cost and time required for generator connection.	EIA-860	Report how much generator paid for grid reinforcements, direct (other) connection costs, and the date of the initial connection request.	For newly activated generators, add questions to Schedule 3, Part B, Line 4.
4. Load-serving entity cost and quality of transmission service.	EIA-861	Report percent of supply covered by long-term contracts, percent covered by firm service (or financial transmission rights), transmission service expense, and curtailments (megawatthours) of firm and non-firm service in past year.	Schedule 2, Part B.
5. Generator cost and quality of transmission service.	EIA-906	Report paralleling that of load-serving entities (see above).	
6. Congestion costs, trade flows and price differentials.	ISO web sites	ISOs define data elements the same way across ISOs and report data to FERC.	None of this information is available for analyzing the effect of restructuring policy outside the ISOs.

The Federal Government, through FERC, will continue to regulate interstate transmission and wholesale prices for the foreseeable future. Chapter 3 focuses on the impact of unbundling on the usefulness of existing financial data collections. Industry unbundling has not been accompanied by unbundling of financial records, all but precluding financial analysis of transmission entities.

As mentioned above, open access to transmission is key to FERC's policies aimed at bringing competition to the wholesale power industry. Chapter 4 reviews the data available for assessing the grid's support of open, more competitive markets. Data are relevant to answering questions such as: Are suppliers able to access and connect to the grid? Are the costs and quality of transmission service nondiscriminatory and reasonable? Is power readily flowing from areas with low prices to those with high prices? Are FERC's policy initiatives succeeding?

The available data are only evidence that the grid is (or is not) being used in ways that are more (or less) consistent with expanding markets and competition. They are not absolute measures of the size of markets or the trade possibilities defined by the grid.

Chapter 5 considers the data available for assessing competition in wholesale markets. The Federal Government is responsible for enforcing antitrust law as well as wire fraud and conspiracy statutes that typically are violated in cases of market manipulation. In the context of FERC's standardized transmission tariff, competitive prices are critical to congestion pricing. If wholesale prices are not competitive, then the economic appeal of using locational prices to manage and pay for congestion is diminished, and transmission expansion decisions may be distorted. The ISOs have substantial information for assessing wholesale competition; outside the ISOs there is little available in the way of useful data.

1. Official Transmission Data

Introduction

This chapter describes official data pertaining to electricity transmission. The following definition of "official data" is used here: information produced by Federal and State governments or their agents or by regulated entities, such as ISOs, and some data produced by NERC. The sources of Federal transmission data are DOE—primarily EIA and FERC—and the RUS. Only the data from NERC that are routinely and readily supplied to DOE, EIA, and FERC are treated as official data.

Transmission Technology, Industry Organization, and Data Collection

Transmitting electricity over long distances is not new. As early as 1893, a hydroelectric generation plant was transmitting alternating current (AC) electricity over a 10-kilovolt (kV) line from San Antonio Creek, California, more than 40 miles to San Bernardino, California.[19] That type of line was not typically connected to lines owned by other generating companies, but by the late 1920s utilities realized that connecting to neighboring systems had economic benefits. Because of different patterns of peak loads and plant outage times in adjacent systems, interconnections permitted significant reductions in total installed capacity without reducing overall service reliability.

Even before World War II, improvements in transmission technology—especially high-voltage transmission lines—permitted electricity to be shipped economically over hundreds of miles. In 1936, for example, the Tennessee Valley Authority built a 230-mile, high-voltage (154 kV) line linking Norris Dam near Knoxville, Tennessee, with Wilson Dam at Muscle Shoals, Alabama.[20] This capability encouraged more utilities to interconnect. Following the East Coast blackout of 1965, utilities banded together and, in 1968, formed NERC to promote reliability of the transmission grid. The Federal Government promoted utility interconnections and regional planning as a means to protect system reliability and encourage economic growth.

Regional transmission planning and coordination are a challenge, in part because of the size of the domestic electricity industry and the variety and number of entities that own segments of the grid. For example, New England's grid delivers more electricity than does the United Kingdom's, and ownership of the U.S. grid is spread across 240 IOUs, 2,009 public utilities, 894 cooperatives, and 9 Federal utilities. Of all electricity sales to end-use customers, IOUs sell about 74 percent of the total, publicly owned utilities about 16 percent, cooperatives about 9 percent, and Federal utilities the remainder.[21] Each type of entity operates in a different regulatory and economic environment, reflecting the evolution of the transmission grid over time in response to particular economic opportunities and common problems facing multitudes of diverse entities. Their diversity is reflected in the data.

Two Federal agencies and two Departments collect information on electricity transmission. FERC collects transmission data from IOUs and other entities it regulates. EIA collects similar information from entities that are outside FERC jurisdiction: independent power producers (IPPs), cooperatives, municipal systems, Federal power systems, and Texas. EIA also collects data from generators under FERC jurisdiction. DOE collects data on North American electricity flows related to trade with Canada and Mexico, and the Department of Agriculture collects data from cooperatives that have loans with the RUS.

Facility owners and system operators collect electrical data at specific points on the grid—generators, substations, and customer meters—to control flows and charge customers for using the system. Electrical control and associated economic data are the building blocks for all other data collections and reporting. Data collection agencies aggregate owner and operator information up the hierarchies of electrical control—from buses to control areas, to ISOs, NERC regions, and Interconnections. The text box below describes the electrical hierarchy.

Government agencies generally attempt to report the data they collect by ownership (regulatory status), electrical control, and political subdivision. Table 1 and the accompanying maps (Figures 1, 2, and 3) show the

[19] U.S. Bureau of Reclamation, *The History of Hydropower Development in the United States* (July 13, 2003), web site www.usbr.gov/power/edu/history.

[20] Web site www.newdeal.feri.org/library/r39.htm.

[21] Energy Information Administration, "Table 1. Selected Electric Utility Data By Ownership, 2000," web site www.eia.doe.gov/cneaf/electricity/public/t01p01p1.html.

structure and number of the electrical control and political hierarchies. Interconnections, ISOs, NERC regions, and States generally encompass a mix of entities with different ownership, regulatory requirements, and boundaries (both geographic and electrical). This organizational complexity alone makes it difficult to estimate regional totals or to develop sharp interregional comparisons, although organizational complexity is not the only challenge.

As electricity markets further develop and mature, the grid's economics and operations are becoming more integrated. Prices, supplies, and reliability are not as closely associated with individual firms as in the past. Neither power flows nor markets begin and end at ownership and jurisdictional borders; and even if they did, individual companies and system operators rarely have complete information on topics of policy interest. Federal and State policymakers are forced to look beyond individual company reports and political boundaries to inform their oversight of the grid.

A fundamental change in the way an industry conducts business, as is now happening in the electricity industry, alters the basic data needed to describe that industry. Federal agencies charged with collecting industry data may need to modify their data collection methods, and on occasion they need to acquire new types of data. New methods of aggregating and disaggregating basic

Electrical Control Hierarchies: Definitions

Interconnection: A connected AC power grid that operates at the same frequency in synchronization. There are three Interconnections in the United States: the Western Interconnection, the Eastern Interconnection, and Texas (ERCOT). AC power lines cannot connect them, because by definition the Interconnections are not synchronized with each other. Direct current (DC) lines can connect them, but because DC lines are expensive and the physical separations are often large, the links between Interconnections are weak.

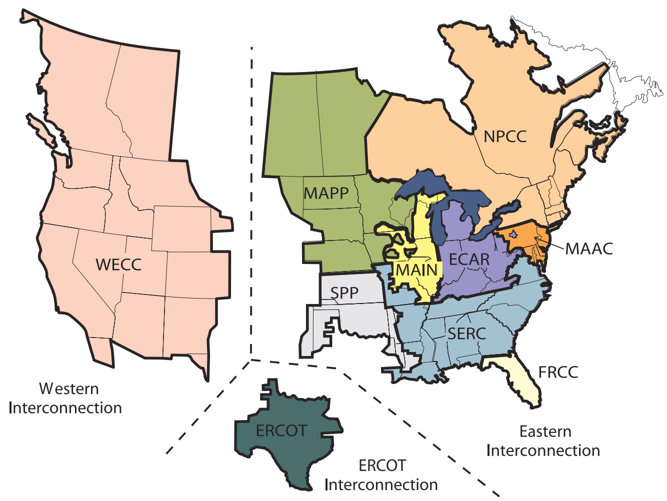
ISO: An organization approved by FERC that oversees, and can control, the operation of generators, transmission companies, and markets within its area. ISOs can function as super control areas to control power flows into and out of their areas.

NERC Region: A voluntary association of interconnected transmission systems and generators that plan, schedule, and operate jointly to ensure that system resources and procedures protect reliability. NERC regions include multiple control areas and can include more than one ISO.

Control Area: An electric system consisting of one or more electric utilities capable of regulating generation to maintain a schedule of electricity flows.

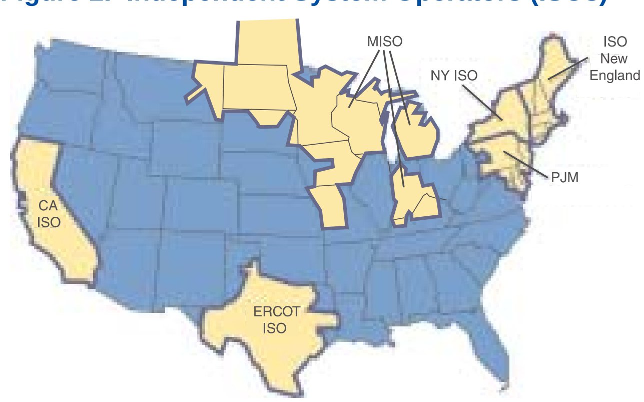
Bus: Any place where wires come together or connect equipment such as generators, transformers, capacitors, and substations to the grid.

Figure 1. NERC Interconnections and Regions



Source: North American Electric Reliability Council.

Figure 2. Independent System Operators (ISOs)



Source: Energy Information Administration and Midwest ISO.

Table 1. Data Collection and Reporting Hierarchies by Electrical and Political/Jurisdictional Entity

Electrical Entities	Number	Political/ Jurisdictional Entities	Number
Interconnections	3	Countries	3
ISOs	6	Census Divisions	9
NERC Regions	10	States (Contiguous)	48
Control Areas	About 140	Utility Service Areas	About 3,100

Source: Energy Information Administration.

reports may also be needed to accommodate new organizational and market boundaries. Given the physical and institutional complexity of the U.S. electricity industry and the variety of government interests in different parts of the industry, it is not surprising that the data required to answer relatively new questions about transmission are uneven and, in some cases, nonexistent.

Official Transmission Data Currently Collected

The official data elements describing the existing system relate to:

- Physical assets
- Configuration of those assets as a power delivery system
- Performance of that system under normal and emergency conditions
- Economic data (cost, investment, and price).

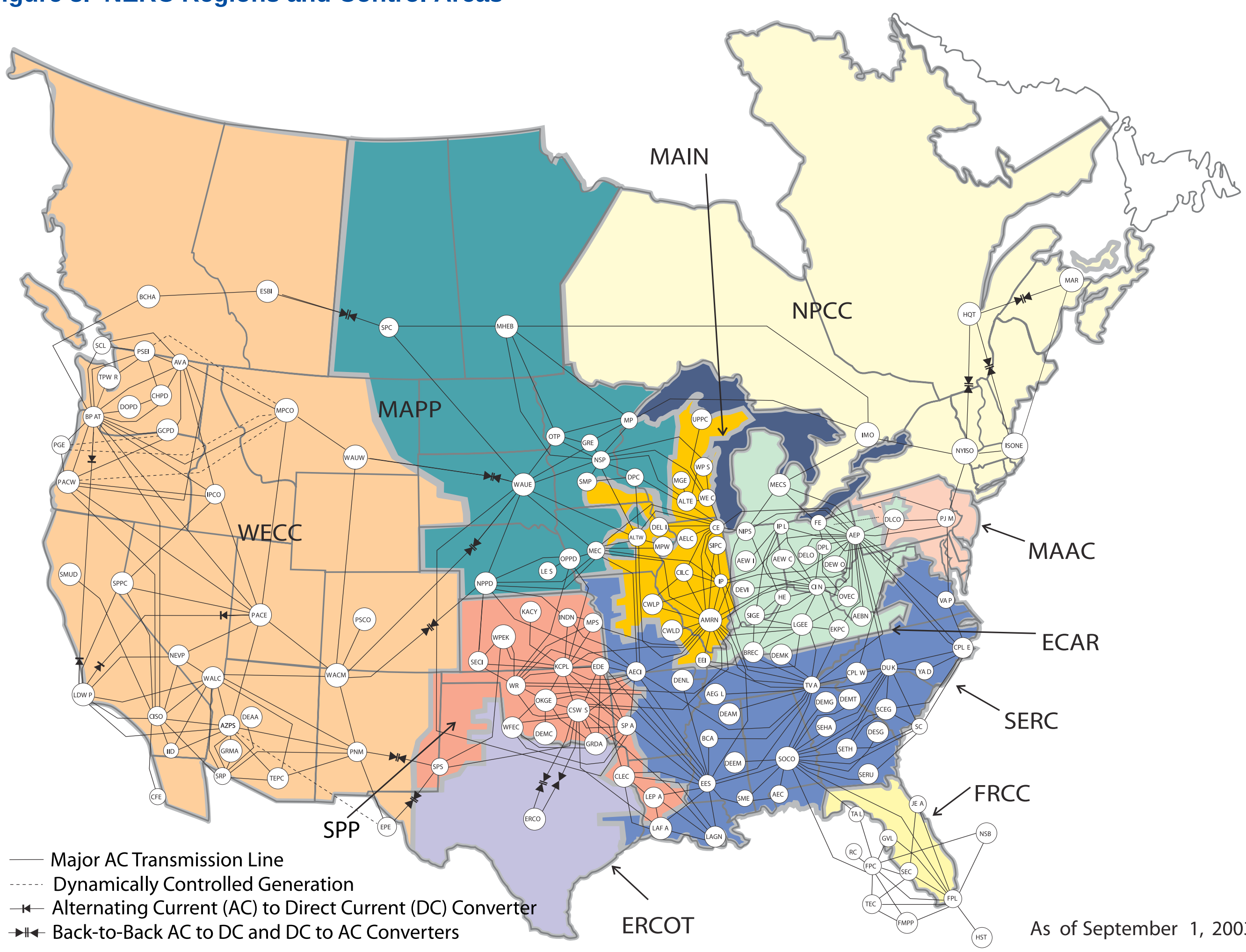
Some of the data refer to generation and demand, because transmission is meaningless without them. The official data describing the planned system include:

- Projected additions and retirements of facilities
- Projected performance of the planned system in meeting future needs.

Most Federal transmission data are collected on survey forms. The Paperwork Reduction Act of 1995 (PRA) requires each Federal agency to seek and obtain approval from the OMB before undertaking a collection of information directed to 10 or more persons, or continuing a collection for which a current OMB approval will expire. Under the PRA, OMB approval for an agency to use a given information collection instrument can last a maximum of 3 years. For questionnaires and forms, agencies are required to provide a public notice in the *Federal Register*, requesting comments from the public and affected agencies, 60 days before submitting the instrument to OMB for review.

The Federal Government currently fields 11 major data collection instruments directly relevant to electricity

Figure 3. NERC Regions and Control Areas



Source: North American Electric Reliability Council.

transmission. Table 2 identifies the forms and their target respondents.

NERC and the ISOs typically produce electronic reports (often databases) on system operations as part of their monitoring and oversight responsibilities. Those reports are specific to the needs of the particular collecting organization and can change quickly. The ISOs and NERC also develop market oversight reports and planning documents, usually annually. NERC data pertain primarily to its members; ISO data mainly involve physical and economic transactions within the boundaries of the ISOs. Data collected and disseminated by the ISOs generally are available on ISO web sites in spreadsheet or database format. Some ISOs provide summary reports on much of the data collected; others simply provide raw data. The data elements that individual ISOs collect and make available to governments and the public vary greatly.

NERC disseminates unique data collections, such as "transmission loading relief" reports (TLRs) filed by Reliability Coordinators.[22] NERC also provides "reliability assessments," based on its own data collections and data from other sources, and makes them available on its web site. The assessments, made at a regional level, provide overviews of system reliability but do not include the detailed data and analyses used by NERC to reach judgments about reliability. In addition to its own data, NERC also provides compilations of data from Form EIA-411 (and additional forms not related to transmission) in its Electricity Supply & Demand Database (ES&D). The ES&D is sold on NERC's web site, and government entities can receive copies upon request.

Table 3 provides a summary of the transmission data currently collected by the Federal Government and associated organizations and lists the available data elements. (Appendix A summarizes the principal Federal transmission data collections.) In Table 3, an empty cell indicates that there is no existing collection for that data element and type on the associated form. The variety of forms directly reflects the complexity of the industry and the electrical system.

Although a particular data element (such as "voltage") may be collected on five different forms, that does not mean it is being collected five times from the same respondents. Rather, different forms may be used to collect similar data from different entities. For example, IOUs report on FERC Form 1, and public power facilities, municipals, cooperatives, and others not reporting to FERC report on Form EIA-412.[23] Those forms essentially identify what is owned by individual companies and other entities. Form EIA-411 associates the rated voltages of power lines and other information with NERC regions. FERC Form 714 collects voltage data by control region. FERC Form 715 identifies nominal operating voltages and a host of electrical parameters by individual line number and buses in an electrical network. Planned transmission elements are reported on Form EIA-411 and FERC Form 715.

Several of EIA's collections can be understood as complementing FERC collections. FERC Form 1 is the major Federal source of data on IOU finances and facilities. Form EIA-412 is used to collect similar data from entities that do not report to FERC. FERC Forms 714 and 715 are important sources of official data used for Federal

Table 2. Current Federal Data Collections Related to Electricity Transmission

Agency	Respondents	Form
FERC	Investor-Owned Utilities	FERC Form 1, "Annual Report of Electric Utilities, Licensees, and Others"
	Control Areas	FERC Form 714, "Annual Electric Control and Planning Area Report"
	Investor-Owned Utilities or NERC	FERC Form 715, "Annual Transmission Planning and Evaluation Report"
EIA	NERC	Form EIA-411, "Coordinated Bulk Power Supply Program Report"
	Public and Federal Generation and Transmission Cooperatives[a]	Form EIA-412, "Annual Electric Industry Financial Report"
	Electric Utilities	Form EIA-417R, "Electric Power System Emergency Report"
	Generators With More Than 1 Megawatt of Capacity	Form EIA-860, "Annual Electric Generator Report"
	Industry Participants	Form EIA-861, "Annual Electric Power Industry Report"
DOE		Form FE-781R, "Annual Report of International Electric Import/Export Data"
RUS	Electric Cooperatives: Electric Distribution Borrowers	RUS Forms 7, "Financial and Statistical Report," and 7a, "Investments, Loan Guarantees and Loans - Distribution"
	Electric Cooperatives: Electric Power Supply Borrowers (Forms 12a-i) and Electric Distribution Borrowers With Generating Facilities Forms 12d-g)	RUS Form 12, "Operating Report - Financial"

[a]EIA's fiscal year 2005 budget does not include funding for the Form EIA-412 survey.
Source: Energy Information Administration.

[22]A Reliability Coordinator is an individual or organization responsible for the safe and reliable operation of the interconnected transmission system for its defined area, in accordance with NERC reliability standards, regional criteria, and subregional criteria and practices.

[23]Because EIA's fiscal year 2005 budget does not include funding for the Form EIA-412 survey, data previously collected on that form will not be available for the year 2004.

Table 3. Transmission Data Elements and Related Collection Systems

Transmission Data Elements	Data Collection Systems		
	About Physical Assets	About System and Performance	Other
Facilities and Physical Assets			
Line Data			
Voltage (AC or High-Voltage DC)	FERC: Form 1 EIA: Forms EIA-412 and EIA-411	FERC: Form 714 and Form 715	
Line Design Information	FERC: Form 1 EIA: Forms EIA-412 and EIA-411		
Capability		FERC: Form 715	
Location (Terminals)	FERC: Form 1 EIA: Forms EIA-412 and EIA-411	FERC: Form 715	
Length (Miles)	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12		
Ownership	FERC: Form 1 EIA: Forms EIA-412 and EIA-411	FERC: Form 715	
Station/Terminal Data			
Name and Location	FERC: Form 1 EIA: Form EIA-411	FERC: Form 715	
Voltages	FERC: Form 1 EIA: Form EIA-411	FERC: Form 715	
Function	FERC: Form 1		
Load (Megavolt-Amperes)	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7	FERC: Form 715	
Other Transmission Facilities	FERC: Form 1 EIA: Forms EIA-412 and EIA-411	FERC: Form 715	
Electrical Configuration			
Electrical Configuration	EIA: Form EIA-411	FERC: Form 714 and Form 715	ISOs[a], NERC[b]
Miles of Line by Voltage	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12		
Control Area Interconnection		FERC: Form 714	
Performance			
System Operating Data			
System Loading		FERC: Form 714	ISOs[a]
Transfer Capabilities			ISOs[a], NERC[b], OATT[c]
Congestion (Duration)			ISOs[a],
Transmission Loading Relief			NERC[b]
System Disturbances		EIA: Form EIA-417	ISOs[a], NERC[b]
Losses	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12	EIA: Form EIA-861	ISOs[a], NERC[b]
Economics			
Cost, Price, Rate, Revenue, and Fee Data			
Capital Costs: Lines and Structures	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12		
System O&M Costs	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12		ISOs[a], OATT[c]
Balance Sheet Information	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12		
Connection Costs			
Transmission Service Rates			ISOs[a], OATT[c]
Ancillary Service Rates			ISOs[a], OATT[c]
Transmission Service Revenues	FERC: Form 1		ISOs[a]
Ancillary Service Revenues	FERC: Form 1		ISOs[a]
Nodal Prices			ISOs[a]
Research and Development Expenses	FERC: Form 1		
Transaction Data[d]			
Interregional Transactions	FERC: Form 1 EIA: Form EIA-412 and Form EIA-411 RUS: Form 7 and Form 12	EIA: Form EIA-861 FERC: Form 714	ISOs[a]
Intraregional Transactions	FERC: Form 1 EIA: Form EIA-412 RUS: Form 7 and Form 12	EIA: Form EIA-861 FERC: Form 714	ISOs[a]
International Imports/Exports		DOE: Form FE-781R	ISOs[a], NERC[b]

[a]Data available from one ISOs are not necessarily available from another ISO; nor are the data always comparable.
[b]NERC may provide access to some of the data elements in this chart that are not noted, however they are not the primary source of the data they disseminate.
[c]Open Access Transmission Tariffs.
[d]This is not an indicator of capability but a validation that the transmission systems facilitate economic transactions.
Source: Energy Information Administration.

oversight of reliability plans, which, in the case of FERC Form 715, includes electrical modeling of the grid. Form EIA-411 includes both information on the "adequacy" of existing and planned generation to meet projected demand[24] and information on new transmission facilities that is not captured on FERC Form 714. Form EIA-411 also includes electrical data on new lines owned by public power companies. Form EIA-417 collects information on power outages, and DOE's Form FE-781R reports international power flows; neither of these data categories is collected by FERC. Similarly, the RUS collects detailed information on cooperatives, which are not under FERC jurisdiction and thus do not report data to FERC.

Table 4. Data Elements for Facility and Reliability Planning

Transmission Data Elements	Planned Data Collection Systems
Electrical Configuration	
Electrical Configuration	EIA: Form EIA-411 FERC: Form 715 NERC
Miles of Line by Voltage	EIA: Form EIA-411 NERC
System Operating Data	
System Loading	ISOs
Congestion	ISOs
Line Data	
Voltage AC or High-Voltage DC	EIA: Form EIA-411 and Form EIA-412 FERC: Form 715 NERC
Capability	EIA: Form EIA-411 FERC: Form 715 NERC
Location (Terminals)	EIA: Form EIA-411 and Form EIA-412 FERC: Form 715 NERC
Length (Miles)	EIA: Form EIA-412
Cost	EIA: Form EIA-412
Ownership	EIA: Form EIA-411 FERC: Form 715 NERC
Project In-Service Date	EIA: EIA: Form EIA-411 and Form EIA-412 NERC
Stations/Terminals	
Location	EIA: Form EIA-411 FERC: Form 715 NERC
Voltage	EIA: Form EIA-411 FERC: Form 715 NERC
Function	FERC: Form 715
Load Megawatts (MW), Megavolt-Amperes Reactive (MVAr)	EIA: Form EIA-411 FERC: Form 715 NERC
Capacitors Volt-Amperes Reactive (VAr)	FERC: Form 715
Project In-Service Date	EIA: Form EIA-411 NERC

Source: Energy Information Administration.

Three Federal collections are the major sources of official planning data (Table 4). Most of the data are used to demonstrate that generation resources will be adequate to meet anticipated future demand. FERC Form 715 focuses on the ability of the transmission system to deliver power where utility planners expect it to be needed under anticipated peak conditions. Together, the data from the three sources are used to assess and monitor the reliability of power delivery in the future.

NERC and ISOs are the other major sources of transmission data. NERC typically works with its members to assemble, verify, and submit the data collected on Form EIA-411 and FERC Form 715. NERC also collects significant amounts of information about power flows, system disturbances, and curtailments.[25] Most of those data are not public and are not immediately or routinely available to the Federal Government. There is no publicly available document describing precisely what data NERC does collect and archive.

ISOs collect and release a variety of performance data as part of their normal operations. ISO high-frequency (hourly) data generally refer to markets—prices, generation, imports, and exports. Although each ISO generates vast amounts of virtually real-time operating, scheduling, planning, and bidding data, the ways in which the data are defined, collected, formatted, and made available to the public are not consistent among the reporting organizations. The data do not necessarily cover matching time frames, nor are the data of the same scope in most cases. ISOs also produce a variety of reports on their market oversight, planning processes, and planned investments. Similar information exists outside of the ISOs but is rarely made public. The data available to describe transmission and related markets in most of the United States are limited to the information collected by the Federal Government.

Many of the suggestions that have been made for improving the quality of data available for public policy analysis of transmission issues involve standardizing data that are now collected within the ISOs, extending that standardized collection to areas outside of ISOs, and coordinating Federal and NERC data collection efforts. Those suggestions, as they pertain to specific aspects of the electricity industry and the official data collection instruments that are relevant in each case, are discussed in detail in the remaining chapters of this report.

[24]Chapter 2 discusses "adequacy" in the context of reliability.
[25]See, for example, "NERC Fast Links," web site www.nerc.com.

2. Reliability

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 the blackout, the U.S.-Canada Power System Outage Task Force identified its proximate causes.[26] That analysis did not, however, address broad public policy questions about the reliability of the electric power system.[27] 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:

- How reliable is the North American electricity transmission grid?
- Is the grid becoming more or less reliable over time?
- Are necessary investments in reliability being made, especially in transmission capability?
- Do market incentives undermine reliability? In particular, do voluntary approaches to reliability management work in a market setting?
- Are markets revealing new ways to attain reliability at less cost?

This chapter reviews official data and analytical tools available for answering such questions and examines the additional types of data the Federal Government needs to meet its reliability oversight responsibilities.

The Federal Government's role in reliability management has been to monitor outages and require IOUs to show that their plans are consistent with reliable operations.[28] DOE also sponsors reliability research, conducts investigations after major outages, and works with industry reliability groups to anticipate reliability problems.[29] 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 NERC.

Since the September 11, 2001, terrorist attacks, the Federal Government has restricted access to certain grid data that were previously available to the 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 requirements will only grow.

After the East Coast blackout of 1965, utilities formed the NERC to develop voluntary reliability standards and guidelines. Membership in NERC is voluntary. NERC encouraged members in each of its 10 regions (see Chapter 1) to maintain enough reserve generation and transmission capability in their exclusive franchise (service) areas to maintain basic service 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 individual investment plans and responses to reliability threats. Everyone generally cooperated in those efforts because reliable operation was in everyone's best interest; no one lost customers to lower cost competitors; and regulators underwrote their costs.

The growth of more competitive wholesale electricity markets since 1996, when FERC issued Order 888, has created new challenges for reliability management. In the past, utilities generally owned both generation and transmission assets dedicated to serving customers in their exclusive franchise areas. Currently, generation and transmission assets are often owned by separate entities and no single entity bears sole responsibility for

[26]U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004).

[27]For examples of differing views see the *New York Times* (August 16, 2003), p. A25: B. Richardson, "Drunk on Power," A. Barabasi, "We're All on the Grid Together," and R. Kuttner, "An Industry Trapped by a Theory."

[28]Form EIA-417 collects data on outages and power quality problems. Form EIA-411 and FERC Form 715 collect facility and electrical data needed for reliability studies.

[29]DOE plays a major role in investigating large-area reliability failures, as discussed in Chapter 3. See, for example, U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), web site https://reports.energy.gov/BlackoutFinal-Web.pdf. The Department's Office of Electricity Transmission and Distribution also sponsors a wide-ranging program of research into technologies to improve reliability and better manage the grid. See web site http://electricity.doe.gov.

system reliability. Franchises are no longer exclusive; wholesale customers typically can buy power from 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 flows to cross system boundaries, and to 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, "Reliability Definitions and Indicators," 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 are a host of useful indicators but no good summary metric. Competition and the August 14, 2003, blackout have highlighted the unstated role of information, computation, and communications in traditional concepts of reliability. The following section, "Markets and Reliability," reviews some of the effects of markets on reliability planning and management and identifies additional reliability indicators. This is followed by a discussion of official reliability data available to the Federal Government. The chapter concludes with suggestions on how gaps in the data might be filled.

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 begins is a matter of controversy. NERC's data and published analysis define the high-voltage grid as 230 kV and above. For FERC Form 715 the reporting threshold for the high-voltage grid is 100 kV, but respondents generally include lines of 69 kV and above. Form EIA-412 defines the high-voltage system as 132 kV and above, and Form EIA-411 uses 230 kV as the high-voltage threshold. The differences matter because there are large areas of the country where 69-kV and 138-kV 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 69 kV.

When the demand for power (load) differs from the amount of generation net of losses, an AC system is unbalanced. If the difference is large enough the system will black out—it will fail to operate in part or in 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.[30] 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 withdrawn from the transmission grid is necessary to maintain reliable service.

Operational control is exercised mainly at the level of the control area, ISO, and NERC reliability region. In rare instances (such as the August 14, 2003, 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 are focused on control areas and NERC regions.

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*** [emphasis added] *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.*[31]

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 that the *level* of reliability should be set so that the marginal benefits of increased reliability (fewer outages or power quality lapses, reduced economic loss) would equal its marginal costs (additional generation, transmission, or better system control).[32] Traditionally, each utility evaluated investment in emergency generation by comparing its cost with the cost of

[30] As mentioned in Chapter 1, the approximately 140 control areas in the United States are the basic units for balancing power flows and maintaining power quality within their areas.

[31] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), p. 218.

[32] When investments are "lumpy," it is not always possible to equate marginal costs and benefits.

unserved energy.[33] 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 that power of sufficient quality costs less than the consumer is willing to pay. When marginal benefit from the consumer's perspective is less than marginal cost (the price of power), the consumer does not consume—i.e., she chooses to black herself out.[34]

Trends in experienced and expected frequencies of blackouts and substandard power quality would give policymakers 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, 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.[35] NERC's qualitative evaluation hinges on two factors:

- 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.
- Security—the ability of the electric system to withstand sudden disruptions, such as electric short circuits or unanticipated loss of system elements.[36]

NERC's focus is on whether operating practices and physical resources within a NERC region, perhaps supplemented with emergency power imports, 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 establish how reliable the system is or whether additional investments would increase reliability or be worth their cost.

Determining generator "adequacy" amounts to summing the capacities 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

Transmission Anomalies

Life in an AC network

- Electrons are not transported, shipped, or otherwise moved from generators to consumers.
- Less is more and more is less—sometimes, depending:
  - Removing lines can increase delivery; increasing a line's capability can decrease delivery.
  - Increasing consumption can relieve heavily loaded lines; decreasing consumption can overload lines.
- Lightly loaded lines often cannot carry more power.
- Fully loaded lines do not necessarily constrain delivery.

Why?

- Electrons in AC systems only move back and forth a small distance; they do not go from here to there.
- In a network there are multiple paths from generators to customers.[a] Electricity flows through a network along *all* possible paths, following physical laws that favor those paths with "least resistance."
- There are no valves for directing electricity along secure routes.
- AC electrical flow has a real and a reactive component. Only the real component transmits power, but the total of real and reactive current determines the load on a link in the circuit.

What that means

- 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.
- Mathematical models are indispensable for sorting out the complexity and accurately showing how the network can meet customers' power demands.

[a]Electricity flows along more than one path (the scheduled, nominal, or dominant path) from a source to a load are called a "loop flow."

[33]F. Schweppe et al., *Spot Pricing of Electricity* (Klur Academic Publishers, 1988), pp. 137-145.

[34]See H. Chao and R. Wilson, "Priority Service: Pricing, Investment, and Market Organization," *American Economic Review*, Vol. 77, No. 5 (December 1987), pp. 899-916.

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

[36]North American Electric Reliability Council, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America* (October 2002), p. 7.

combination of historical experience and modeling results. Because imports can replace the need for local generation, the selection of base imports is important to the generation adequacy assessment. If the comparison shows that the amount of adjusted capacity exceeds the amount needed with a sufficient margin of safety (usually about 15 to 20 percent 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 of the system (a statement of the connections between lines and buses), the limits of all the branches, 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.[37] 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.

Engineers also need models of the region's connected neighbors to determine whether base imports are feasible and whether additional (incremental) imports would be available to 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.[38] These analyses result in limits on "the maximum amount of electricity that can be safely transferred over transmission lines,"[39] which 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.

Large blackouts and brownouts of the high-voltage U.S. grid, while not uncommon, are infrequent enough to make statistically estimating regional probabilities and their trends 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:

- Number, size, duration, and cost of blackouts and brownouts
- Trends and status of grid adequacy and security
  - Peak demand, supply and power flows by control area
  - Line outages
  - Security limited lines, power curtailments, and redispatch
- Planning data
  - Projected demand
  - Projected generation and transmission assets
  - Power transfer capabilities
- Analytical tools
  - Electrical models of regions, both as they currently exist and as described in planning documents
  - Contingency lists.

[37]Thermal limits are imposed to prevent overheating of lines due to excessive power flows. An accessible discussion of kinds of line limits can be found in U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), pp. 7-8.

[38]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 are 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, *n-2* limits become the relevant constraints.

[39]U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), p. 8.

Markets and Reliability

The emergence of regional and interregional wholesale markets has had a significant impact on the utilization of power lines and the volatility of power flows. NERC has stated 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 . . . .*[40]

and

> *. . . [O]perating experience shows that market conditions can, at times, cause volatile and unpredicted flow patterns that cannot be reliably accommodated by the transmission system.*[41]

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

Operators require good interregional models, precise data, and rapid computation and communications to manage novel and increasingly volatile power flows successfully.[42] The U.S.-Canada Task Force concluded that three of the four basic causes for the initiation of the August 14, 2003, blackout were related to information technology: inadequate system understanding, inadequate situational awareness, and failure of reliability organizations to provide effective diagnostic support.[43] The task force also found that neither NERC nor the Federal Government maintained reference models of the directly affected regions or 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, 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 that 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 their resistance to paying for idle or underutilized assets that benefit everyone else.

State regulators also question why citizens in their States 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.*[44]

How to pay for reliability in a competitive environment is far from settled. The northeastern ISOs have had some success in using markets to provide mandated reserve generation capacity and various operating reserves; however, no one has demonstrated a market-based way of deciding the appropriate level of reliability and paying for it.[45]

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 that 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.[46] 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:

- High-quality, interconnection-wide models

[40]North American Electric Reliability Council, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America* (October 2002), p. 20.

[41]North American Electric Reliability Council, *2003 Summer Assessment: Reliability of the Bulk Electricity Supply in North America*, p. 8.

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

[43]U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), pp. 18-19.

[44]North American Electric Reliability Council, *NERC Reliability Assessment 2002-2011: The Reliability of Bulk Electric Power Systems in North America* (October 2002), p. 28.

[45]Academic economists have proposed market mechanisms for determining reliability and paying for it. See H. Chao and R. Wilson, “Priority Service: Pricing, Investment, and Market Organization,” *American Economic Review*, Vol. 77, No. 5 (December 1987), pp. 899-916.

[46]Oak Ridge National Laboratory, *Load as a Reliability Resource in Restructured Electricity Markets*, ORNL/TM2001/97 (June 1, 2002). See also C. Goldman, G. Barbose, and J. Eto, “California Customer Load Reductions during the Electricity Crisis: Did they Help to Keep the Lights On?,” *Journal of Industry, Competition and Trade*, Vol. 2, No. 1-2 (2002), pp. 113-142.

- Actual investment in the high-voltage grid, including specific investments in instrumentation, communications, computation, and control
- Usage (MWh) metered to permit real-time price-responsive demand and 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 complement planning projections and give policymakers a factual basis for reconsidering 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 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.

Official Data on Reliability

Reliability Incidents, Outage Probabilities, and Costs

Federal data on experienced lapses in grid reliability are confined to Form EIA-417, "Emergency Incident and Disturbance Report." Form EIA-417 incident data have been used primarily as a starting point for grid security analyses. This form must be submitted to DOE's Operations Center if one or more of the following apply:

- Uncontrolled loss of 300 megawatts or more of firm system loads for more than 16 minutes from a single incident
- Load shedding of 100 megawatts or more
- System-wide voltage reduction of 3 percent or more
- Public appeals to reduce the use of electricity
- Actual or suspected physical attacks that could affect electric power system adequacy or reliability
- Actual or suspected cyber or communications attacks
- Fuel supply emergencies
- Loss of electric service to more than 50,000 customers for 1 hour or more
- Complete operational failure or shutdown of the transmission and/or distribution system.

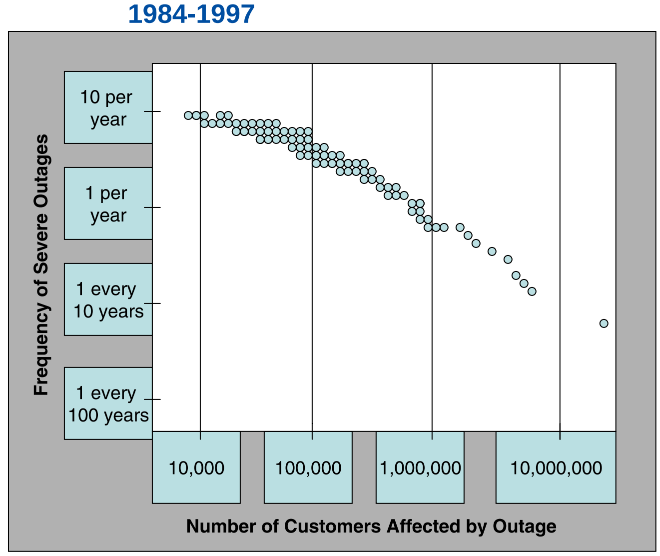
The types of data collected on Form EIA-417 include information about the location, date, and time of the incident, as well as the nature of the disturbance. Information about the cause of the incident (if known) and the actions taken in response to the incident are also requested. To illustrate, Table 5 provides a list of some typical disturbances and unusual occurrences that were reported on Form EIA-417 during 2002.

Of the 23 incidents reported, 7 were in California and 2 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 they are spread around the country and involve a small percentage of delivered power nationwide. At the regional level of aggregation, the historical data suggest that the frequency of failures is very low.

Outage Probabilities

John Doyle of the California Institute of Technology, and others, have used NERC data to identify outage frequencies in North America from 1984 through 1997 (Figure 4).[47] Their work shows that the frequency of large outages is significant. Similar displays can be constructed from EIA data. The frequency of large outages follows a

Figure 4. North American Power System Outages, 1984-1997



Note: The circles represent individual outages in North America between 1984 and 1997, plotted against the frequency of outages of equal or greater size over that period.

Source: U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Washington, DC, April 2004), p. 103.

[47] See B.A. Carreras, D.E. Newman, I. Dobson, and A.B. Poole, "Evidence for Self-Organized Criticality in a Time Series of Electric Power System Blackouts," submitted to the *IEEE Transactions on Circuits and Systems Part 1* (May 2002), web site http://ffden-2.phys.uaf.edu/papers/carrerasCAS02preprint.pdf.

power law, implying that the probability of outages does not vanish as their size increases: very large outages cannot be ruled out as a practical matter. There are, however, too few very large outages to demonstrate that observed frequencies are accurate estimates of underlying probabilities at the regional level. For the same reason, empirical estimates of changes in outage probabilities are of unknown accuracy.

Costs

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

The Electric Power Research Institute (EPRI), the insurance industry, and other researchers have attempted to compute annual costs resulting from power incidents. Those 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 more

Table 5. Major Disturbances and Unusual Occurrences on the U.S. Electricity Grid, 2002

Date	Utility/Power Pool and NERC Region[a]	Time	Area	Type of Disturbance	Loss of Load (Megawatts)	Number of Customers Affected	Restoration Time
January							
1/30/2002	Oklahoma Gas & Electric (SPP)	6:00	Oklahoma	Ice storm	500	1,881,134	2/7/2002 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)	16:00	Missouri	Ice storm	210	95,000	2/10/2002 21:00
February							
2/27/2002	San Diego Gas & Electric (WSCC)	10:48	California	Interruption of firm load	300	255,000	2/27/2002 11:35
March							
3/9/2002	Consumers Energy Co. (ECAR)	12:00	Lower Peninsula of Michigan	Severe weather	190	190,000	3/11/2002 12:00
April							
4/8/2002	Arizona Public Service (WSCC)	15:00	Arizona	Vandalism/insulators	0	0	4/9/2002
July							
7/9/2002	Pacific Gas & Electric (WSCC)	12:27	California	Interruption of firm power	240	1	7/9/2002 19:54
7/19/2002	Pacific Gas & Electric (WSCC)	11:51	California	Interruption of firm power (unit tripped)	240	1	7/19/2002 16:30
7/20/2002	Consolidated Edison Co. of New York (NPCC)	12:40	New York	Fire	278	63,500	7/20/2002 20:12
August							
8/2/2002	Central Illinois Light Co. (MAIN)	12:43	Illinois	Interruption of firm power	232	53,565	8/2/2002 18:36
8/9/2002	Lake Worth Utilities (SERC)	8:23	Florida	Interruption of firm power	51	25,000	8/9/2002 12:13
8/25/2002	Pacific Gas & Elec. (WSCC)	3:41	California	Interruption of firm power	120	1	8/25/2002 9:17
8/28/2002	Lake Worth Utilities (SERC)	14:09	Florida	Severe weather	67.6	25,000	8/28/2002 15:38
October							
10/3/2002	Entergy Corporation (SPP)	3:33	Coastal Areas of Southern Louisiana	Hurricane Lily	NA	242,910	10/4/2002 9:00
November							
11/6/2002	Pacific Gas & Electric Co. (WSCC)	22:00	Northern and Central California	Winter storm	270	939,000	11/10/2002 12:00
11/17/2002	Long Island Power Authority (NPPC)	15:48	Northport, NY, and Norwalk, CT	Cable tripped	0	0	NA
11/17/2002	Northeast Utilities (NPCC)	6:00	Northwest and North Central Connecticut	Ice storm	NA	224,912	11/21/2002 8:00
December							
12/3/2002	Entergy Corporation (SPP)	18:30	Arkansas	Ice storm	NA	43,000	12/5/2002 8:00
12/11/2002	Dominion-Virginia Power/North Carolina Power (SERC)	13:09	Northern Virginia to Fredericksburg and Staunton to Harrisonburg	Winter storm	63	130,000	12/11/2002 13:45
12/14/2002	Pacific Gas & Electric (WSCC)	11:00	Northern and Central California	Winter storm	180	1,500,000	12/18/2002 16:00
12/19/2002	Pacific Gas & Electric (WSCC)	6:00	Northern and Central California	Winter storm	56	385,000	12/20/2002 17:00
12/25/2002	PPL Corporation (MAAC)	17:00	Eastern Pennsylvania	Winter storm	250	106,000	12/26/2002 5:00
12/25/2002	Metropolitan Edison Co./ First Energy (MAAC)	10:00	Reading, York, Hanover, and Hamburg, Pennsylvania	Winter storm	NA	95,630	12/27/2002 8:30

[a]NERC regions are defined in the Glossary.
NA = not available.
Source: Form EIA-417, "Electric Emergency Incident and Disturbance Report."

than $400 billion.[48] 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.*[49]

The lack of cost data makes it impossible to balance the costs of reliability investments against 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 affect grid adequacy and security.

FERC Form 714, "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. Significantly for reliability assessment, the form also records how the control area met peak hourly demand in each month.

FERC Form 714 is a double-entry account, so that net transactions between adjacent control areas are reported directly. Because control areas are associated wholly and uniquely with NERC regions, estimates of regional interchange could in principle be made by aggregating individual reports.[50] 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; e.g., one control area reports a delivery, but the named recipient does not report a receipt. The information on power flows between control areas is not sufficiently accurate, complete, or frequent to be useful in assessing the grid's ability to deliver power to control areas that need it, when they need it.

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 10 regional reliability councils and by many transmission-owning utilities. For example, ECAR (the East Central Area Reliability Coordination Agreement) has reported several interesting trends.[51] Availability of the 345-kV system in ECAR in 2001 was the second lowest in 20 years, primarily because scheduled outage time increased by 95 percent. The ECAR report notes that several of the longer outages in 2001 were attributable to work being done to connect independent generators to the grid.[52] Similar availability data are not reported in a standard form across NERC regions and are not readily available for lines of 69 kV and above.

Sustained increases or decreases in line loadings on a heavily loaded transmission path, corridor, or interface can indicate a change in grid adequacy. The direction of power 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. These data are maintained by NERC but are not publicly released.

A more direct measure of adequacy would be the number of hours that *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 redispatching the system to meet demand. This information is generally not available.

One publicly available indicator of grid adequacy is NERC's Transmission Loading Relief Database. The information is unique to the Eastern Interconnection.[53] This "Log" contains information about instances of

[48] J. Eto et al., *Scoping Study on Trends in the Economic Value of Electricity Reliability to the U.S. Economy*, LBNL-47911 (Berkeley, CA: Lawrence Berkeley National Laboratory, June 2001), p. 14.

[49] *Ibid.*, p. x.

[50] "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. Because exchanges are explicitly balanced on FERC Form 714, no distortion should be introduced by the exclusion.

[51] East Central Area Reliability Coordination Agreement, *2001 Transmission Line Outages Summary Report*, 02-TFP-46 (December 2002).

[52] *Ibid.*, p. 5.

[53] FERC has endorsed the use of transmission loading relief orders to individual generators to keep line flows below area interchange limits. Those 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).

transmission inadequacy at flow gates (major pieces of transmission equipment) and on major lines. In particular, it documents the requirement to implement NERC's TLR procedures on specified days to protect major parts of the transmission system.[54] Similar information is not available for either the Western Interconnection or ERCOT. The northeastern 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 all higher levels 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 5 shows a plot of TLR level 2 events by month of the year. Not surprisingly, TLRs increase significantly during the peak demand months of July and August. NERC does not report the volumes of power that are curtailed by TLRs. NERC did, however, provide that information to FERC staff writing the December 2001 curtailment study cited in Chapter 4, Table 19.

Planning Data

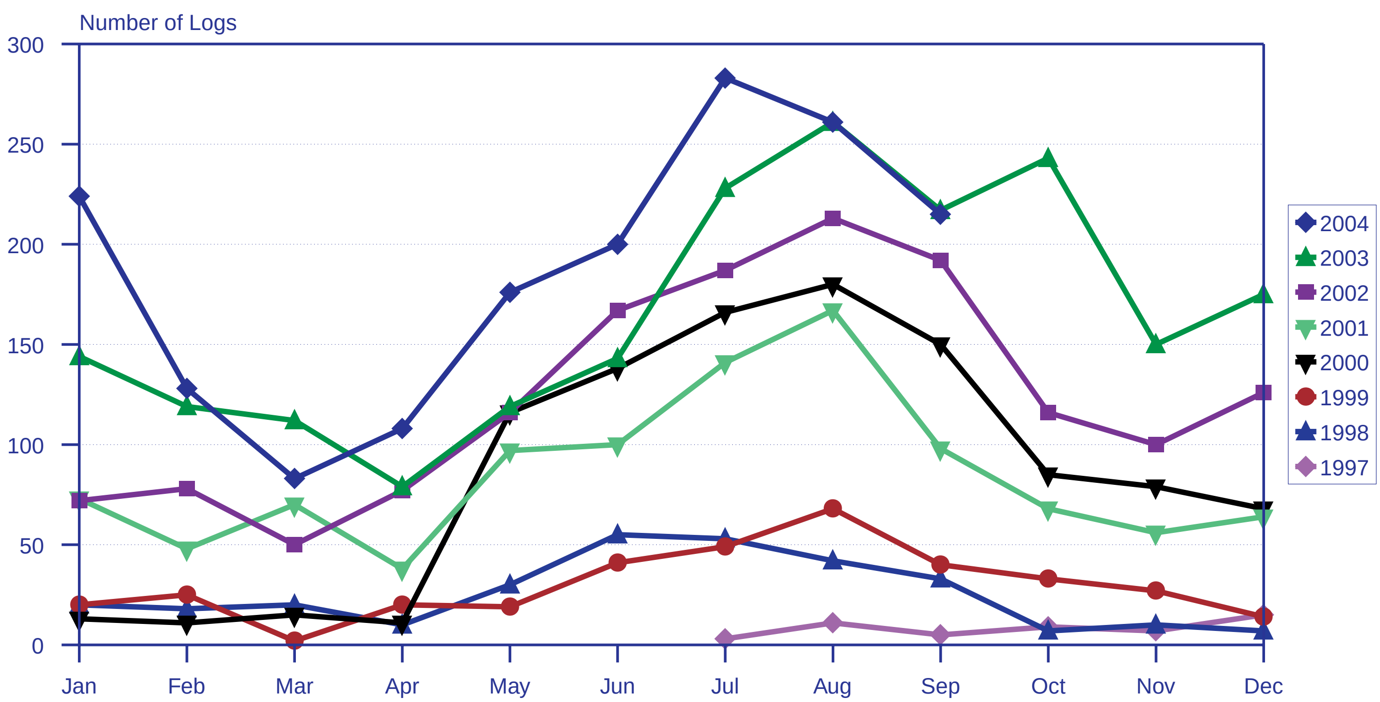
The starting point for establishing prospective adequacy is estimated future demand, especially peak demand. FERC Form 714 requires planning areas to report their actual hourly demand and to provide forecasts of summer and winter peak demand 10 years into the future. The historical data could provide a benchmark for projections and serve as important data for modeling future demand.

NERC submits Form EIA-411 on behalf of its 10 regional councils. The data include 5-year projections of supply and demand by NERC region. Supply means generation, but the form also identifies existing transmission lines and proposed lines. The data can be used to indicate whether projected generation within a NERC region exceeds projected demand. The form does not, however, contain the kinds of information necessary to determine whether intra- and interregional transmission are sufficient to deliver power where it is demanded under peak or other definable conditions.

The coverage and relevance of the data collected on Form 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 be consistent with those used in NERC's reliability assessments or with the planning area projections reported on FERC Form 714.

As referenced above under "Reliability Definitions and Indicators," NERC assesses power transfer capability

Figure 5. Level 2 or Higher Transmission Loading Relief Reports by Month, 1997-2004



Source: NERC.

[54]NERC's web site,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."

between interconnected regions and subregions and publishes the "base" power transfers between regions and the incremental transfer capabilities in each direction. Those data provide a measure of the additional power that could be transferred from one region to a neighboring region that experienced a sudden need for support. High levels of incremental capability indicate adequacy; low levels indicate the potential for shortages to spread from one region to neighboring regions. Table 6 shows the transfer limits from MAIN to MAPP, SERC, and TVA, under the conditions that NERC expected during the summers of 2000 through 2003.

The capabilities are generally substantial, although the values are for non-simultaneous conditions; i.e., these limits could not all be approached at the same moment. The limits also assume that all transmission facilities are in service, all facilities are loaded within normal ratings, and voltages are within normal limits.

The limits are 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 6. The annual variations in base and incremental flows are sufficiently large that they can be estimated only with the help of models.

Analytical Tools

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

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.[55] Transmitting utilities or their agents that operate networks at or above 100 kV submit the form to FERC annually. Normally, NERC Regional Councils submit Form 715 on behalf of their members. The required data include:

- Power flow base cases for the respondent's transmission system or, if the transmitting utility belongs to a regional or subregional transmission planning or reliability organization, power flow base cases for that region or subregion
- System maps
- Descriptions of reliability criteria
- Evaluations of the transmission system's current and future performance.

The power flow cases are intended to be forward looking. FERC suggests that the cases include summer and winter peak conditions for 1, 2, and 5 to 10 years into the future. FERC also suggests that respondents include an analysis of light and heavy transfers 1 year in the future.

Form EIA-411, "Coordinated Bulk Power Supply Program Report," requires power flow data similar to those provided on FERC Form 715 for newly planned transmission facilities.[56] Specifically, Form EIA-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.

Table 6. Base Transfers and Incremental Transfer Limits Among Selected NERC Reliability Regions and Subregions, 2000-2003
(Megawatts)

	From MAIN to MAPP-US			From MAIN to SERC TVA			From MAIN to ECAR		
Year	Base	Incremental	Incremental/ Base (Percent)	Base	Incremental	Incremental/ Base (Percent)	Base	Incremental	Incremental/ Base (Percent)
2000	-235	1,900	-808.51	-388	3,300	-850.52	-61	4,000	-6,557.38
2001	-214	950	-443.93	-28	2,300	-8,214.29	55	4,000	7,272.73
2002	-214	950	-443.93	172	2,100	1,220.93	3	4,000	133,333,33
2003	392	1,000	255.10	-28	2,800	-10,000.00	905	3,200	353.59

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

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

[56]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.

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

The utility of the FERC Form 715 data 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-specified names, making it expensive to merge EIA and FERC data. Contingency lists are unavailable, although the instructions would seem to require them. And the information provided on service areas is not sufficient to locate demand centers (load buses).

FERC Form 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 to exist in the future. This has two consequences: First, it is not possible to use the FERC Form 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 selecting 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 capability. In fact, the cases do not specifically identify new transmission facilities; that information is available on Form EIA-411.

The electrical models that can be constructed directly from these data include only the reporting area and some of the lines connecting it to outside areas. Most of the Form EIA-411 and FERC Form 715 data are 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 that faces temporary shortages. That is what NERC does with its incremental transfer limits discussed above.

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 this be done. For many years NERC has sponsored committees to piece together their individual FERC Form 715 filings into a description of the Eastern and Western Interconnections. 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 interconnection-wide perspective.

As demonstrated by the August 14, 2003, 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.[57] As the grid becomes increasingly integrated, the need for interconnection-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 own costs low and can offer better terms than can "good citizens." Data on actual investments in the high-voltage grid—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 3, FERC Form 1 reports aggregate investments and does not make a clear distinction between distribution and high-voltage transmission.

The advent of real-time pricing would make it possible for customers to respond to prices and give system operators an additional tool for ensuring reliable service. As discussed in Chapter 5, there is little official information on how much load is currently metered to allow real-time pricing, or the amount of power that is being sold at real-time rates.[58]

[57] See, for example, E. Lipton, R. Perez-Pena, and M. Wald, "Overseers Missed Big Picture as Failures Led to Blackout," *New York Times* (September 13, 2003), pp. A1 and A10.

[58] Georgia Power and Gulf Power, among others, provide information about their real-time and time-of-use programs on the web site www.metering.com.

Filling the Information Gaps

In the 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 development, together with the entry of independent generators supplying local and distant markets, means that reliability is increasingly dependent on building and managing transmission capability.

Data collections that the Federal 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 and data necessary to verify the reliability of the existing system or to assess 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 to improve control of the high-voltage grid and indicators of reliability trends are not routinely available to the 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 Federal Government's capability to oversee reliability could be achieved without new data collections. Instead, if FERC modified Form 715 and rigorously monitored 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 Form 715 power flow models frequently show electrical violations and reporting errors, and they do not necessarily describe the existing grid. Government oversight would be enhanced if the planning regimes described in FERC Form 714 and Forms EIA-411 and EIA-860 were among the cases evaluated in FERC Form 715. FERC and EIA could accomplish that by first requiring the planning data on FERC Form 714, Form EIA-411, and Form EIA-860 to describe the same "plan."[59] FERC could then, for example, require that the FERC Form 715 power flows show how well the plan provides for "adequacy" and "security" 1, 3, and 5 years into the future. Table 7 shows many of the specific changes that would be required in existing FERC and EIA forms.

When reference power flow models are available for regions, it will be appropriate for the Federal Government and NERC to construct interconnection-wide

Table 7. Reliability Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. High-quality power flow models of existing and planned systems.	FERC 715	1. Identify load buses by MSA.[a] 2. Add selected 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 uneven. 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 selected 715 cases (2 above). 2. Experienced line and voltage violations. 3. Use EIA/EPA generator names and same line/bus identifiers as on FERC Form 715.	
3. A consistent set of reference reliability plans.	FERC 714, EIA-411, EIA-860	1. Require Forms EIA-411 and EIA-860 data to describe the same plan. 2. Require FERC Form 714 (Part 111, Schedule 2) and Form EIA-411 demand projections to be consistent.	These plans should be the basis for the power flow analyses 1, 3, and 5 years into the future.
4. Monitor potential demand response.	EIA-861	Add a schedule showing annual total megawatthours metered hourly (or higher frequency) and megawatthours billed by time of consumption.	To quantify extent of price responsive demand (see Chapter 5).
5. Investment in metering and control of the high-voltage grid .	FERC 1, EIA-412	1. Adopt NIPA definition of investment. 2. Report investment in metering, communication, software, and control of the high-voltage grid.	See Chapter 3.

[a]MSA stands for Metropolitan Statistical Area. An MSA is a geographic entity defined by the U.S. Office of Management and Budget. Qualification as 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).

[59]Form EIA-860 does require that identified planned power plants and generators be taken from "planning data." Planning data are not defined on the form.

models. The government's ability to monitor trends in reliability could be substantially improved if NERC and FERC built a time series database on security limits experienced on high-voltage lines and flowgates; curtailments; denied service; and power flows across the high-voltage grid. That would require a formal agreement between FERC and NERC. Data on the costs of blackouts and substandard power quality, including what people spend to protect themselves, would also be useful. Given the other needs, however, those data are of relatively low immediate priority.

3. Financial Performance and Investment

Introduction

Within two weeks of the blackout on August 14, 2003, the *Wall Street Journal* reported:

> *The nation's electric power industry . . . is preparing to launch a public-education campaign to help it raise $100 billion from investors, governments, and consumers to upgrade the nation's power grid.*[60]

The estimate seemed plausible to the press, given the Federal Government's frequently expressed concerns about investment in the Nation's power grid; but within 3 months, *Public Utilities Fortnightly* published an article that stated:

> *We don't know what caused the . . . blackout but somehow we know that our transmission system needs $50 billion to $100 billion in investment and upgrades. And utilities need higher returns . . . . The reality is that we aren't short $50 billion or $100 billion . . . . [T]he study said to support that conclusion doesn't do the job.*[61]

For the foreseeable future, Federal and State policymakers will remain at the center of these controversies. Their policy decisions will greatly affect the level of investment, where investment occurs, the profitability of the transmission business, who pays for transmission service, and how much they pay. To make informed decisions, policymakers require relevant and accurate data to guide their judgments.

FERC is charged with ensuring "just and reasonable" prices for power in interstate commerce. State regulators continue to be deeply involved in transmission regulation in most States. They effectively regulate transmission costs and prices for "internal transactions" and also control siting and eminent domain.

FERC has long collected data on capital and operating costs from IOUs. FERC uses the information to ensure that tariffs for delivered electricity sales bear a reasonable relation to costs. EIA complements the FERC collections with less detailed reports from other generation and transmission owners to produce industry-wide totals. Both agencies focus on generation and distribution data, because the costs of transmission are a small portion of total costs. In 2000, for example, the transmission operating costs of major public utilities averaged only 4 percent of their total operating costs.[62] Transmission plant was 11 percent of total electric plant in service.[63] In a cost-of-service world where all costs are bundled together to form a single price for delivered electricity, the specific costs of transmission are unimportant.[64]

Restructuring of the electricity industry has broadened FERC's perspective beyond cost recovery to the economics of transmission. FERC Order 2000, establishing RTOs, notes that "effective and efficient RTOs . . . [are] dependent in large measure on the feasibility and vitality of the standalone transmission business."[65]

The difficulty in obtaining financial data that show "vitality" is that transmission is rarely a standalone business. Almost all IOUs derive most of their total revenues from supplying bundled power (energy, transmission, and services) to native customers at State-regulated prices. Separate transmission prices and revenues for internal customers do not exist. Merchant transmission companies only sell transmission, but they are minuscule. Cooperatives and public power entities are not in the business of selling transmission capacity. The only "market-like" transmission prices are those that customers pay for wheeling power across a system. Wheeling

[60] J.J. Failka, "Power Industry Sets Campaign to Upgrade Grid," *Wall Street Journal* (August 25, 2003), p. A3.

[61] S. Huntoon and A. Metzner, "The Myth of the Transmission Deficit," *Public Utilities Fortnightly* (November 1, 2003), p. 28.

[62] Energy Information Administration, *Electric Power Annual 2001*, DOE/EIA-0348(2001) (Washington, DC, March 2003), Table 8.3, "Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (With Generation Facilities), 1990 through 2001," p. 51, web site http://tonto.eia.doe.gov/FTPROOT/electricity/034801.pdf.

[63] See Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 2000*, DOE/EIA-0437(00) (Washington, DC, November 2001), Table 11, "Electric Utility Plant for Major U.S. Publicly Owned Generator Electric Utilities at End of Period, 1996-2000," p. 20, web site www.eia.doe.gov/cneaf/electricity/public/t11p01p1.html.

[64] The transmission grid's relatively small costs do not mean that its efficient operation and development are unimportant. Efficiency reduces costs in the short run and ensures that the grid is not a drag on economic growth and competition. Efficient grid operation generally means that the grid's services are priced at marginal cost. Efficient development means that all potential investments are considered and the investments made are those whose net benefits, adjusted for risk and timing, are greatest. The need to consider all relevant investments is easy to overlook. Line congestion, outages, and other transmission problems may best be solved by investments in distributed generation, demand-side management, or other alternatives to transmission facilities.

[65] Federal Energy Regulatory Commission, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (June 6, 2000); FERC Stats. & Regs. at 31, 170.

revenues, however, are a very small portion of total revenues.

Measures of Financial Performance and Investment

There is considerable agreement about how financial performance—unlike reliability—should be measured, and how financial data should be interpreted. There are, nevertheless, long-standing debates about how to obtain better agreement between accounting and economic values and how to value uncertain prospects and illiquid assets. FERC requires that utilities it regulates use the Uniform System of Accounts. Those accounts are more detailed and require far more disclosure than is usual for publicly traded companies.

FERC collects financial and operating data annually from major privately owned electric utilities on FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others."[66] FERC requires utilities under its jurisdiction to submit the following schedules for the calendar year:

- Comparative Balance Sheet
- Statement of Income
- Retained Earnings
- Statement of Cash Flows
- Notes to Financial Statements.

The data are entered on the form pursuant to the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act.

The transmission revenues reported on FERC Form 1 are those for wheeling power for others. Form 1 specifically identifies 15 subcategories of transmission operation and maintenance costs (page 321), as well as the book values (acquisition costs) for 9 subcategories of transmission plant and equipment (page 206). The form also identifies calendar year additions to transmission plant and equipment. The revenues from transmission of electricity for others (Account 456) are segmented into energy charges, demand charges, and other charges. FERC has proposed to require explicit reporting of purchases and sales of ancillary services.[67] Debt, stockholder equity, taxes, and miscellaneous expenditures are listed and described in detail. In addition to providing FERC with information to assist in reviewing company tariffs and investments, FERC Form 1 is used by financial analysts to assess private utilities' short-term solvency, financial risk, long-term viability, and returns to investment and investors.

EIA collects data on an abbreviated version of FERC Form 1—Form EIA-412—on an annual basis from publicly owned utilities (municipalities, political subdivisions, States, and Federal entities). EIA requires the following schedules for the respondent's fiscal year:

- Balance Sheet
- Income Statement
- Electric Plant

Ratio Analysis

Financial analysts often examine operating efficiency ratios and operating profitability ratios to better understand how firms generate profits. In a typical application, a financial analyst would decompose return on equity (ROE, equal to net income divided by equity) into components to highlight differences among firms. A popular decomposition is the DuPont identity, which expresses ROE as the product of profit margin, total asset turnover, and financial leverage:

$$\text{Return on Equity} = \begin{bmatrix}\text{Net Profit}\\ \text{Margin}\end{bmatrix} \times \begin{bmatrix}\text{Total Asset}\\ \text{Turnover}\end{bmatrix} \times \begin{bmatrix}\text{Financial Leverage}\\ \text{Multiplier}\end{bmatrix}$$

$$= \left[\frac{\text{Net Income}}{\text{Sales}}\right] \times \left[\frac{\text{Sales}}{\text{Total Assets}}\right] \times \left[\frac{\text{Total Assets}}{\text{Equity}}\right] .$$

An example of two hypothetical firms, both of which earn 12 percent per year on equity, illustrates how these decompositions assist in financial analysis:

Firm	Net Profit Margin	Asset Turnover	Financial Leverage Multiplier	ROE
A	8%	2.0	0.75	12%
B	3%	1.0	4.00	12%

While both firms have the same ROE (12.0 percent), the underlying means of generating ROE are very different. Firm A has high net profit margins, high turnover, and low financial leverage. Firm B has low net profit margins and low operating efficiency but has used financial leverage to increase its return. Richard Brealey and Stewart Myers discuss the limits of DuPont ratios in *Financing and Risk Management* (New York, NY: McGraw-Hill, 2003), p. 366.

[66]FERC has proposed collection of quarterly financial data on a new Form No. 6-Q. See Federal Energy Regulatory Commission, "Quarterly Financial Reporting and Revisions to the Annual Reports," 18 CFR Parts 141, 260, 357, and 375 (June 26, 2003).

[67]Federal Energy Regulatory Commission, "Quarterly Financial Reporting and Revisions to the Annual Reports," 18 CFR Parts 141, 260, 357, and 375 (June 26, 2003), Appendix B.

- Taxes, Tax Equivalents, Contributions, and Services During the Year
- Sales of Electricity for Resale
- Electric Operation and Maintenance Expenses.

Like FERC, EIA collects data on wheeling revenues. EIA encourages, but does not require, respondents to use the Uniform System of Accounts. Analysts use the data to compare the operations of publicly owned utilities and IOUs and to evaluate potential public exposure to their debt. EIA uses the data to complete its statistical description of the industry.

No system of accounts, no matter how conscientiously applied, captures all economic values perfectly. Transmission equipment, for example, is very long-lived, making book values poor measures of either replacement or market value. Most utility land holdings, likewise, were acquired long ago, and valuable rights-of-way assets were originally obtained under the implicit threat of eminent domain. Market values for many such assets are unavailable.

Impact of Restructuring on Relevant Financial Data

FERC Order 888 required all public utilities that own or control interstate transmission capacity to functionally unbundle wholesale power services. Functional unbundling requires the public utility to do the following:

- Take transmission services under the same tariff as others
- Post separate rates for wholesale generation, transmission, and ancillary services
- Rely on the same information system that its customers use.

FERC considered, but did not require, divestiture of transmission from generation and institutional changes to achieve functional unbundling. Nor did it require public utilities to spin off transmission into standalone business units.

With the growth of independent power suppliers, the transmission business has become something of a mongrel. The utility that owns transmission capacity earns revenues by charging others posted rates for wholesale transmission and related services; it charges itself for its own wholesale sales at the same rates. The utility neither posts transmission rates for bundled retail sales nor charges itself for transmission. Instead, the charges for transmission are bundled with the price of delivered power. Because FERC has not required "financial unbundling" by line of business, it is not possible to identify total transmission revenue or to know whether the utility is charging nondiscriminatory rates for transmission service to retail customers.

Because reasonable transmission rates for others are defined in part on the basis of costs, sharp distinctions between transmission costs and the costs of distribution and generation are important under restructuring. FERC Form 1 allows respondents to determine their own boundaries, making meaningful comparisons across transmission providers difficult if not impossible.

An implicit assumption behind financial accounts is that each company's revenues and costs capture its major economic benefits and costs. Before system interconnections and large power flows across systems became important, integrated utility costs and benefits were essentially the same as total costs and benefits; i.e., they were internal to the utility. The same identification is dubious in a restructuring electricity industry.

An economically important external cost occurs when one system's operations load lines in another system (or systems) to the extent that an affected system cannot use its lines as it otherwise would. Lines loaded to their security limits are congested. In a connected AC system, electricity flows everywhere in response to relative line resistance (impedance) and the locations and amounts of generation and consumption. How an operator decides to dispatch generators, secure imports, or otherwise meet (or refuse to meet) demand can cause lines to be congested far outside his or her system's boundaries. Faced with line congestion, operators can only meet their customers' increased demands by operating more costly, but better situated, generators. Those additional costs show up in the books of the affected system; costs are artificially lower in the books of the system causing the congestion.[68]

Congestion costs within individual systems are being measured and valued (inconsistently) in a few parts of the country. Chapter 4 contains a discussion of congestion costs and revenues. Those costs are not identified on FERC Form 1.

FERC's Order 2000 would bring together many transmission providers into a few RTOs. In a regional setting, individual companies cannot be held solely responsible for the costs borne by customers. A particular company may experience abnormally high costs because it has made expenditures that reduce overall regional costs; another may have artificially low costs because it exploits "beggar thy neighbor" opportunities.[69] In a restructured industry the costs of an RTO as a

[68]Operating decisions that relieve congestion and lower costs in other areas are not compensated either.

[69]One role of RTOs is to internalize significant external costs and manage them on an equal footing with each system's cash costs.

whole—not just its individual companies, which report on FERC Form 1— would be relevant to costs, tariffs, and investments.

Restructuring has also motivated public policy concern about the level and kinds of investment being made in the grid. FERC Form 1 collects data on transmission plant and equipment and additions to plant and equipment. Unlike the National Income and Product Accounts, the "additions" data are not restricted to acquisitions of new equipment. "Plant and equipment" refers to the purchase price of any qualifying good, including land, regardless of its age. When a utility sells old equipment at above net book value to another reporter, the data show net additions, despite the fact that nothing has changed on the ground. Generators have been sold for much more than net book value in the recent past. Net additions (after subtracting land acquisitions) may or may not be a good proxy for the economic concept of investment.

As mentioned in Chapter 2, NERC has stated that power flows today are more volatile and more likely to change course than they were before restructuring. In the present environment, investment in system metering, communication, computation, and control is critical to improving reliability. Capital investment in these areas is not identified on FERC Form 1.

Restructuring has also brought about transmission investments from new entities, such as merchant transmission companies. As discussed in Chapter 4, new independent generators are making significant investments in the grid as a condition of connecting to it. Because FERC does not require merchant companies and independent generators to submit detailed financial reports, those investments may not be recorded in official data.

In a fully restructured environment, financial data for evaluating the economics of transmission would include:

- Standalone financial accounts for the transmission business
- Estimates of external costs and benefits, especially the value of congestion
- Integration of individual transmission provider accounts to the appropriate RTO
- Complete investment totals that identify investments undertaken for grid control.

Official Transmission Financial Data

Standalone Accounts

Except for those few utilities that are strictly dedicated to transmission, it is not possible using official data to construct standalone financial statements for transmission. Both Form EIA-412 and FERC Form 1 identify transmission sold (purchased) from others. FERC has proposed that utilities report the grid's sales (purchases) of ancillary services. Neither form reports transmission nor related services provided to the utility's own generators. As a consequence, it is not possible to calculate transmission's returns on either investment or equity. Ratio analysis of the kind sketched above cannot be performed. Official data do, however, indicate how restructuring has affected revenues from transmission sales to others.

Transmission Revenues

Transmission for others, called wheeling, has grown since the start of restructuring (1996) in some regions and declined in others. Nationwide volumes and revenues more than doubled from 1996 to 2001. Tables 8 and 9 show gross wheeling volumes and revenues for utilities located in the North Central States (ECAR), Midwest (MAPP), and West (WECC) NERC regions and for the total United States.

Figure 6 shows the average revenue per MWh from wheeling for the three regions, which varies from a low of slightly more than $1 per MWh in 1994 in the MAPP region to highs of slightly less than $6 per MWh in 1998 and 2000 in the ECAR region. Over time, the range in price difference among the three regions has varied between roughly $0.50 per MWh and $4.50 per MWh.

Revenues from Grid-Supplied Ancillary Services

FERC does not currently collect information on the prices, volumes, or revenues earned from ancillary services provided in the transmission sector, although it has proposed collecting information on ancillary service revenues. Because the grid is often the major, if not sole, source of ancillary services, however, it would also be useful to collect price and corresponding volumetric information, which could be used to determine whether grid-supplied services are priced at marginal cost. The OASIS sites of transmission providers contain some ancillary service prices, but they are incomplete, do not include volumes, and are not maintained as a time series (see Chapter 4). The ISOs report some scattered, incomplete information on their web sites.

Operations and Maintenance Costs

Official data also include utility operating costs. Table 10 shows the total operations and maintenance costs for utilities in the WECC, MAPP, and ECAR regions. In 2002, wheeling revenues were about 75 percent of operations and maintenance costs in the ECAR region, almost 60 percent in WECC, and about 25 percent in MAPP.

Book Values of Plant and Equipment

FERC maintains voluminous records on the book values of plant and equipment and their depreciation. FERC's

Table 8. Gross Volume of Wheeling in Three NERC Regions, 1993-2002
(Billion Kilowatthours)

Year	ECAR	MAPP	WECC	United States
1993	28.4	14.1	74.6	268.6
1994	26.2	16.5	65.2	252.6
1995	29.7	15.5	64.4	264.2
1996	55.2	15.2	69.7	303.8
1997	61.7	17.2	67.4	326.4
1998	67.6	18.7	73.7	373.3
1999	67.9	22.2	76.9	370.1
2000	85.4	18.8	87.1	490.5
2001	157.3	18.8	112.1	671.8
2002	159.4	13.8	105.5	705.8

Source: Energy Information Administration, based on the Resource Data International (now Platts) PowerDat compilation of data from FERC Form 1.

Table 9. Gross Revenue from Wheeling in Three NERC Regions, 1993-2002
(Million 2002 Dollars)

Year	ECAR	MAPP	WECC	United States
1993	109.29	22.14	224.50	1,362.01
1994	112.27	21.99	212.91	1,365.09
1995	121.15	30.03	198.17	1,373.15
1996	189.08	38.31	231.88	1,541.67
1997	235.31	61.04	240.63	1,821.70
1998	370.58	57.21	232.01	2,181.30
1999	335.68	44.20	294.18	2,417.00
2000	484.71	51.17	352.33	2,828.12
2001	546.53	56.15	469.15	3,400.21
2002	632.31	56.13	470.24	3,968.41

Source: Energy Information Administration, based on the Resource Data International (now Platts) PowerDat compilation of data from FERC Form 1.

concentration on the book value of transmission assets reflects its concern with the recovery of prudent costs, including a reasonable return on capital. These historical costs, and their associated debt, will continue to be important to FERC's determination of capital recovery for wholesale transmission. The difference under restructuring is that the precise boundaries between transmission, generation, and distribution matter.

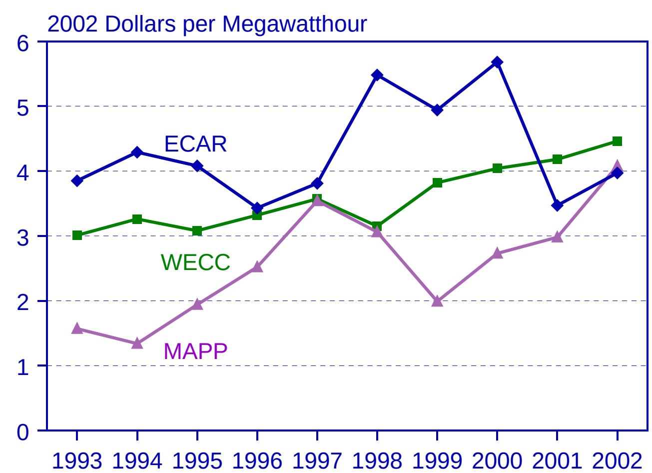
External Costs and Benefits

The Uniform System of Accounts underlying FERC Form 1 does not attempt to identify or value the benefits and costs that responding utilities impose on others. Congestion and reliability are leading examples of these costs and benefits, respectively. Congestion internal to the northeastern ISOs is being valued and paid for by market participants. Chapter 4 explains how congestion is valued and presents recent estimates of congestion costs.

Regional Accounts

FERC does collect data from RTOs or ISOs; however, utilities are not required to provide separate accounts for their assets in different RTOs or ISOs. This is not a problem currently, because most of the U.S. electricity industry operates outside the RTO/ISO structure; but at

Figure 6. Gross Revenue from Wheeling in Three NERC Regions, 1993-2002



Source: Energy Information Administration, based on the Resource Data International (now Platts) PowerDat compilation of data from FERC Form 1.

Table 10. Total Operations and Maintenance Costs for Transmission in Three NERC Regions, 1993-2002
(Million 2002 Dollars)

Year	ECAR	MAPP	WECC	United States
1993	414.27	182.66	1,003.33	2,623
1994	423.20	205.65	1,021.57	2,631
1995	412.54	213.68	1,016.04	2,744
1996	420.06	223.42	1,044.68	2,598
1997	400.53	249.22	1,091.33	3,363
1998	442.11	340.38	1,264.55	3,789
1999	448.54	269.00	1,293.42	4,018
2000	540.14	274.36	1,166.54	4,401
2001	691.16	203.12	950.95	4,089
2002	810.76	220.70	827.02	5,238

Source: Energy Information Administration, based on the Resource Data International (now Platts) PowerDat compilation of data from Form EIA-412, FERC Form 1, and RUS Forms 7 and 12.

such time as those organizations come to operate large portions of the grid, consolidated regional accounts may become necessary for evaluating regional transmission costs and investments.

Utility Investment and Capital Stock

Much has been made of the slow growth in the high-voltage grid relative to the growth in electricity generation. For example, NERC publishes an annual compilation of lines 230 kilovolts and above. As shown in Table 11, the number of high-voltage transmission circuit miles has grown at a compound rate of about 0.6 percent per year since 1990, while generation has grown at a compound rate of nearly 2 percent per year from 1990 through 2002.

Annual "investment" data show little change in response to either generation or increased wholesale trade (see Table 20 in Chapter 4). FERC Form 1 and Form EIA-412 record capital additions for publicly owned utilities and IOUs. RUS Forms 7 and 12 report investment data for cooperatives. Table 12 shows annual capital additions to transmission plant in service from 1988 through 2002. Some of the additions represent purchases of existing facilities (and land) and therefore are not investments in the sense of the National Income Accounts. As noted earlier, publicly owned utilities report to EIA on a fiscal year basis and IOUs report on a calendar year basis. The annual totals are thus a mixture of fiscal and calendar year expenditures. Moreover, the boundaries between transmission and distribution vary among reporters.

Independent Power Producers, Merchant Transmission, and RTO/ISO Investments

Independent power producers do not report their costs for connecting to the grid. To some extent, the costs they incur for grid reinforcement may be reported on FERC Form 1, but if so they are not identifiable. Merchant transmission companies do not report capital investment to either FERC or EIA. RTOs and ISOs are considered utilities by FERC and are required to report.

Table 11. Comparison of Changes in High-Voltage Transmission Infrastructure and Electricity Generation, 1990-2002

Year	Transmission Lines (Circuit Miles)[a]	Generation (Billion Kilowatthours)
1993	147,271	3,038
1994	148,059	3,074
1995	149,020	3,084
1996	150,953	3,197
1994	150,826	3,248
1995	150,111	3,353
1996	152,098	3,444
1997	153,533	3,492
1998	154,679	3,620
1999	155,669	3,694
2000	156,435	3,802
2001	157,314	3,736
2002	158,605	3,838

[a]Includes AC and DC lines 230 kilovolts and above.

Sources: **Transmission Lines:** North American Electric Reliability Council, Electricity Supply and Demand Database software (2003), available at web site www.nerc.com. **Generation:** Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 2003).

Filling the Information Gaps

FERC collects capital and operating cost data from IOUs as part of its responsibility to ensure just and reasonable electricity prices. EIA complements the FERC collections with less detailed reports from the other generation and transmission owners to produce industry-wide totals. FERC's Commissioners are concerned with the economics of transmission as a standalone enterprise because of their obligation to ensure just and reasonable prices in a restructuring environment. But FERC's financial accounts are more appropriate to the circumstances of

Table 12. Annual Capital Additions to Transmission Plant in Service, 1988-2002
(Million Dollars)

Year	Nominal Dollars				Total 2002 Dollars
	Public Utilities	Investor-Owned Utilities	Cooperatives	Total	
1988	910.48	2,027.85		**2,938.33**	**4,053.31**
1989	1,126.49	2,179.64		**3,306.13**	**4,393.48**
1990	522.33	2,622.63		**3,144.96**	**4,022.00**
1991	811.06	2,174.25		**2,985.31**	**3,684.37**
1992	789.26	2,498.62	3.38	**3,291.26**	**3,965.35**
1993	683.33	2,378.64	121.63	**3,183.60**	**3,745.63**
1994	614.52	2,529.35	191.84	**3,335.72**	**3,844.74**
1995	964.96	2,430.74	191.03	**3,586.73**	**4,045.69**
1996	1,300.00	2,312.90	206.90	**3,819.81**	**4,226.86**
1997	851.96	1,957.70	149.74	**2,959.40**	**3,212.23**
1998	640.78	2,173.06	255.16	**3,069.00**	**3,290.61**
1999	708.58	2,308.66	156.19	**3,173.43**	**3,354.35**
2000	929.74	2,612.89	192.55	**3,735.18**	**3,866.69**
2001	836.67	4,217.03	246.27	**5,299.97**	**5,359.81**
2002	1,124.13	3,302.30	220.33	**4,646.75**	**4,646.75**

Source: Energy Information Administration, based on the Resource Data International (now Platts) PowerDat compilation of data from Form EIA-412, FERC Form 1, and RUS Forms 7 and 12.

integrated regulated utilities selling bundled electricity in a cost of service environment.

Apart from a few "transmission only" entities, FERC Form 1 says little about the economics of transmission. Official data do not capture transmission's financial performance, in large part because most transmission revenue is bundled with revenue from retail sales and is not separately identifiable.

If transmission were fully unbundled, its revenues would be unambiguous. Absent that, FERC could require line-of-business reporting—a fundamental change that would be tantamount to introducing a new data collection form. How useful or valid the resulting estimates would be is a serious question.

Far less dramatic changes to FERC Form 1, Form EIA-412, and Form EIA-860 would make the data more useful for cost and investment (but not financial) analysis. Precise definitions of transmission would be a logical place to start. The available data describing transmission operation costs, capital stock, and investment are not comparable across reporters, because neither FERC Form 1 nor Form EIA-412 imposes a common definition separating transmission from distribution.

The "investment" series derived from official data are flawed in at least three other ways. First, additions to transmission plant and equipment reflect not only new investment but also purchases of existing assets from others, land purchases, and other expenditures that, while relevant for some purposes, are not "investment" in the sense of the National Income and Product Accounts.[70] The EIA forms that are modeled after FERC Form 1 share those attributes. Second, EIA, unlike FERC, collects financial data on a fiscal year basis rather than a calendar year basis. Consequently, EIA and FERC investment and other financial data cannot be added to arrive at a valid national total. Third, official data do not appear to capture investment in the grid by new market participants: merchant transmission companies and independent power producers.

Official financial statistics are not informative about transmission revenues and costs, such as ancillary service and redispatch costs, that restructuring makes visible in prices. As Regional Transmission Organizations become more prominent, it will be increasingly important to allocate transmission costs to particular organizations. The kinds of changes to existing forms that would be required are shown in Table 13.

Table 13. Financial and Investment Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. Consistent separation of transmission from distribution accounts.	FERC 1, EIA-412	Explicitly define transmission in the same way for all utilities and use that definition in assigning costs, revenues, and net capital.	Current data are an "apples and oranges" mix.
2. Utility investment in the high-voltage grid.	FERC 1, EIA-412	1. Adopt NIPA 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.	Current "additions to plant and equipment" data have very limited use for economic and reliability analysis, although they are important to capital cost recovery.
3. IPP investment.	EIA-860	Collect direct connection and grid reinforcement costs from IPPs on EIA 860.	Some of these investments may not be picked up on FERC Form 1. See Chapter 4.
4. Merchant transmission investment.	EIA-412	Add to the list of respondents and require them to report transmission investments, as defined above, and to fill out Schedules 10 and 11.	Merchant investment and line data are not currently collected.
5. Ancillary service revenues.	FERC 1, EIA-412	Require reporting as proposed by FERC.	
6. Re-dispatch costs.	FERC 1, EIA-412	Require reporting.	Only applicable to utilities owning generators. Not necessary for ISOs.
7. Regional costs.	FERC 1, EIA-412	Require reporters to disaggregate cost, revenue, net capital stock, and investment by appropriate region.	This would allow regional cost comparisons.
8. Consistent aggregation.	EIA-412	Adopt FERC definitions (see above) and require reporting by calendar year.	EIA currently allows reporting by fiscal year.

4. Transmission and Wholesale Power Markets

Introduction

For almost a decade, FERC has been attempting to create competitive wholesale electricity markets by opening the Nation's electricity transmission grid to competing generators, by promoting regional transmission markets, and by encouraging investment in transmission capability.[71] If its policy initiatives succeed, FERC would transform large areas of the country into "common markets" for electricity commerce. The transmission grid would become a network of superhighways for markets, seamlessly moving power across the country to reduce costs and improve reliability.

Despite FERC's efforts, much of the United States remains more like a collection of loosely connected toll roads than a network of superhighways. Unlike the interstate highway system, the high-voltage grid has hundreds of owners, including governments and IOUs, each manning a tollbooth. Each transmission owner built a section of the grid to serve its retail customers (native load), and interconnections between systems were primarily for improving reliability and sharing occasional surpluses. The grid was not designed or built with the idea of supporting large regional markets.

Electricity markets are dependent on the grid to connect buyers and sellers and to consummate trade agreements. When lines serving Chicago, for example, are congested, outside suppliers are unable to deliver additional volumes, and shortfalls in meeting demand must be met by higher cost local generation. Generators located within such load pockets are well positioned to charge prices significantly above their relatively high (marginal) costs. Congestion effectively fragments markets to the detriment of competition.

Even when transmission resources are sufficient to move power to higher price areas, buyers and sellers may be unable to execute mutually beneficial trades, because each region has its own rules, operating practices, and charges for importing and exporting power.[72] The administrative difficulties and costs of coordinating power flows across system boundaries can be serious obstacles to trade. Resolution of these "seams" issues is a prerequisite for further market integration.

This chapter considers data useful for gauging the grid's support of larger, more competitive markets. Data are needed to answer questions such as: Are generators able to access and connect to the grid? Are the costs and quality of transmission service nondiscriminatory and reasonable? Are bottlenecks, load pockets, and large congestion costs prevalent? Are the costs of moving power across system-control boundaries large and growing? Is power readily flowing from low-price to high-price areas? Are there persistent and large differences in regional wholesale prices? Are FERC's policy initiatives succeeding?

The available data are only evidence that the grid is (or is not) being used in ways that are more (or less) consistent with expanding markets and competition. They are not absolute measures of the size of markets and the trade possibilities the grid defines.

Measuring the Grid's Impact on Wholesale Markets

The fundamental measures of the grid's impact on markets are the potential size of the markets (defined by the grid's capabilities) and the volumes of economic trade they could support. Economic trade is undertaken in response to price differences: the greater the difference in price, the greater is the volume tending to flow to the higher priced market. Market organization, regulation, and transaction costs can cause actual market size and trade volumes to be substantially less than their potential.

Electrical models of the grid are generally necessary to determine which suppliers are physically able to serve markets.[73] Unlike highway transportation, geographic separation neither measures transmission "distance" between generators and markets nor explains its cost.

[71]See Federal Energy Regulatory Commission, *Promoting Wholesale Competition through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, Final Rule, 18 CFR Parts 35 and 385 (April 24, 1996); *Regional Transmission Organizations,* Order No. 2000, Final Rule, 18 CFR Part 35 (January 6, 2000); *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design,* Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. RM01-12-000 (Washington, DC, July 31, 2002); and *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid,* Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. PL03-1-000 (Washington, DC, January 15, 2003).

[72]"Region" here refers to the full range of electrical control hierarchies, including Control Areas, ISOs, RTOs, and NERC regions.

[73]FERC has used confidential company sales information in merger cases to establish historical market boundaries. That information neither identifies all potential suppliers nor shows the effect of changes in grid configuration and use patterns on the list of potential competitors. Chapter 2 contains a brief discussion of electrical models.

Electrical models are also necessary to determine how much power could be moved from suppliers to markets. Unlike a highway, a transmission line may be congested (unable to carry more energy) when carrying only a fraction of its rated capacity. The Federal Government does not maintain reference electrical models of the grid and, therefore, has limited means to establish potential market size. Practicable measures focus on data showing the grid's support of competitive markets.[74] Among these historical data series are:

- Grid access and generator connection
- Cost and quality of transmission service
- Load pockets and transmission bottlenecks
- Congestion costs
- Seams costs (trade barriers)
- Economic trade and regional price differences.

Access refers to a generator's ability to put power into the grid. Denial of service forces generators out of the market. Statistics on access requests and service denials show the grid's support of generator competition and can reveal unequal treatment of market participants. Generator connection data show the grid's accommodation of new entrants—all eventually requiring access in order to compete.

Quality of transmission service refers to the different types of service available to customers. Types of service include point-to-point or network, and firm or interruptible. Firm service all but guarantees reliable transmission service, whereas interruptible service can be suspended (curtailed) for a variety of economic and operational reasons. In most of the United States, firm service is negotiated between transmission owners and customers. In the Pennsylvania-New Jersey-Maryland (PJM) Interconnection and the New York ISO, transmission service is firm if customers agree to pay applicable congestion charges. In PJM, customers can buy financial transmission rights (FTRs), also called fixed transmission rights, which allow the holder to recover congestion charges incurred in flowing power between the two points specified in the FTR.

Generators need firm service to sell into ISO capacity markets and to assure customers that their contracted energy will be delivered.[75] Data showing that firm transmission service is increasingly available and less costly, and that curtailments are decreasing, would be evidence that the grid's performance in supporting commerce is improving.

Bottlenecks refer to constraints on the grid's physical ability to deliver power while respecting security limits. Congestion costs are a measure of the cost of these limits. Data showing temporal declines in bottlenecks and congestion costs would indicate that transmission is becoming less of a constraint to market integration and competition.

Seams costs refer to administrative, coordination, and other institutional obstacles to trade between control areas. To ensure reliability, control-area operators require the sending and receiving parties to schedule power flows and agree on price and other terms in advance. Outsiders typically must make scheduling arrangements and pay fees that insiders do not face. PJM imposes a fee for exporting power outside its borders. These coordination and pricing arrangements—"seams issues"—increase the cost of moving energy between markets and limit market integration.

Economic trade refers to the movement of power between markets in response to price differences. Economic trade within and across regions is a powerful force both for limiting the ability of local producers to raise prices and for efficient resource allocation. When the local price of petroleum and other energy sources exceeds the outside price by more than transportation costs, imports increase. By analogy, data showing large volumes of electricity flowing regularly from lower to higher price areas would suggest that the grid is supporting competition.

Matters are not so simple, however, with electricity. As mentioned in Chapter 2, electricity on an AC system cannot be directed from individual generators to individual customers. Instead, generators put power onto the grid and their customers take power off the grid. Some power flows across boundaries are inadvertent, and although these "loop flows" do not represent commercial transactions, they can be large.

Another minor complication is that electricity can flow from higher priced to lower priced areas. In extreme cases, which do occur in practice, customers are paid for taking more power. This inversion of normal commercial practice happens because transmitting power to lower price areas can at times reduce even higher congestion costs elsewhere on the grid.

Even with these anomalies, data showing a strong tendency for significant volumes of power to flow in the direction of higher price would suggest that the grid is supporting economic trade. Increasing economic trade and narrowing price differences would be consistent

[74]Competitive markets are characterized by a large number of independent suppliers vying to sell to a large number of informed customers. See Chapter 5.

[75]Customers can be responsible for acquiring transmission capacity. Load-serving entities can purchase FTRs to insure their agreements with generators.

with improvement in the grid's support of market competition.

However useful these data are for identifying market trends and documenting current conditions, they can only record what has already happened. By themselves they are imperfect guides to how electricity market size and trade potential change in response to changes in the grid's configuration, its management, and its economic organization. Valid inferences about the quantitative impact of future and hypothetical conditions require realistic electrical models.

Data Showing the Grid's Support of Markets

Access

FERC's OASIS is the primary source of data on grid access, available capacity, transmission rates, and other aspects of transmission. Each public utility or its agent that owns, controls, or operates transmission facilities in interstate commerce is required to post data prescribed by FERC on a web site and to make them available to market participants, FERC, State regulators, and the public.[76] FERC requires the data to be available on the site for 90 days and to be retained for 3 years. FERC itself does not maintain a single consolidated web site for transmission data.

There are currently 22 OASIS web site nodes that serve as gateways to 168 transmission provider web sites.[77] Two of the nodes and six of the provider sites are in Canada. The number of firms listed in a node varies: the Western States Coordination Counsel (WSCC) lists 30 transmission providers; the East Central Area Reliability (ECAR) node lists 3. Some transmission providers not regulated by FERC (nonjurisdictional entities) voluntarily maintain OASIS web sites, including 8 firms in the Electric Reliability Council of Texas (ERCOT), the Bonneville Power Administration, the Western Areas Power Administration, the Sacramento Municipal Utility District, and the Tennessee Valley Authority.

Entergy's OASIS site illustrates the kind of data that are available. The site contains information on type of service, volume, and number of hours requested; price of service; affiliation with Entergy; and whether the request was granted. Table 14 reports the disposition of 1,216 requests for non-firm, point-to-point service requested through Entergy's OASIS site for the month of June 2003. About 96 gigawatts of transmission capacity was requested by 24 entities, of which a total of 3.7 gigawatts (about 4 percent of the total requested) was refused. Of the 24 companies requesting service, 2 were affiliates of Entergy, which jointly filed 696 (57 percent) of the requests, leaving 22 unaffiliated entities with 520 requests. The volume of capacity reservations requested by Energy affiliates averaged twice the volume requested by non-affiliates. Non-affiliates were refused more capacity in aggregate, and their total of 1,870 megawatts refused constituted 7 percent of their total capacity requests.

Although FERC mandates their minimal content, OASIS web sites vary considerably in their look and feel. As part of the research for this report, the author asked FERC staff to extract comparable data from several OASIS sites. The FERC analysts reported that identical queries succeeded or failed depending on the site: each site had its own language; some sites would not allow data to be downloaded; and some sites would not permit downloading data in a standard ".cvs" or spreadsheet file. There is no official database that maintains and archives time series of the information on the OASIS sites.

New Generator Entry

Form EIA-860 reports when generators connect to the grid and their major characteristics, including location, size, primary fuel consumed, and ownership. Table 15 reports 173 gigawatts of new capacity—most of it gas-fired combined-cycle and turbine units—added from

Table 14. Non-firm Point-to-Point Transmission Service Provided by Entergy in June 2003

Entities Requesting Service		Service Requests		Megawatts Requested				
Type	Number	Total	Refused	Total	Refused	Average Requested	Average Refused	Percent Refused
Affiliates.	2	696	20	69,134	1,793	99	90	2.6
Non-Affiliates . .	22	520	27	26,727	1,870	51	69	7.0
Total	**24**	**1,216**	**47**	**95,861**	**3,663**	**79**	**78**	**3.8**

Source: Entergy OASIS web site, http://oasis.e-terrasolutions.com/OASIS/EES.

[76]See Federal Energy Regulatory Commission, *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, Final Rule, 18 CFR Part 37 (April 24, 1996); and *Standards and Communications Protocols for Open Access Same-Time Information System (OASIS)*, Version 1.4, Docket No. RM95-9-014 (January 26, 2000).

[77]The web site address of the central clearinghouse is www.tsin.com.

1995 through 2002.[78] This represents a 23-percent increase over the 1994 national total capacity of 763 gigawatts.[79] The table also shows that most of the capacity expansion has occurred in the nonutility sector, specifically among iIPPs that do not own transmission facilities.

Figure 7 shows that the new units are widely distributed by NERC region. The Southeastern Electric Reliability Council (SERC), already the region with the largest amount of generation capacity, added the most new generating capacity, with more than a quarter of the total new capacity. ECAR's expansion was roughly proportionate to its size, whereas ERCOT added a disproportionately large amount of new capacity relative to existing capacity. These developments reflect in part the replacement of older, less efficient steam units with new combined-cycle technology. California (California-Southern Nevada Power), in response to the crisis of 2000-2001, showed much greater activity in 2001 and 2002 than it had from 1995 though 2000. The New York ISO reports relatively little additional new capacity, indicating that either new units or expanded access to transmission will be needed to meet increasing demand in the next few years.[80]

EIA data show neither how much generators pay to connect (direct and for system enhancements), nor the time required between application for service and connection. EIA's connection data are in the public domain.

Cost and Quality of Transmission Service

OASIS is also the primary source of data on the availability and cost of firm and interruptible service. Entergy's web site again provides an example, as shown in Table 16.[81] Entergy does not offer long-term non-firm service or hourly firm service. In addition to the charges specified in Table 16, transmission customers must purchase ancillary services from Entergy at its posted rates and make up for transmission losses with additional generation (3 percent of the delivered volume).

What is not available on OASIS is how much individual generators and load-serving entities actually pay for transmission of wholesale energy.[82] In some areas the costs include explicit congestion fees and the costs of transmission rights in addition to the types of charges Entergy lists. Annual statistics on the quantity of power that utilities wheel and revenues from wheeling are available, as discussed in Chapter 3. It is not possible to tell, however, whether average annual data accurately represent the charges wholesale customers face at peak times, seasonally, or at all locations served by the service provider.

OASIS does not identify how much of each market participant's generation or demand volume is covered by firm transmission service. Although a customer has arranged for transmission service, either firm or interruptible, the power may not be delivered; i.e., it may be

Table 15. New Generating Capacity Added by Type of Ownership, 1995-2002
(Megawatts Summer Capacity)

Year	Investor-Owned		Publicly Owned		Independent Power Producers		Other Nonutility		Total	
	Capacity	Number of Units	Capacity	Number of Units	Capacity	Number of Units	Capacity	Number of Units	Capacity	Number of Units
1995	3,774	53	1,212	40	530	53	2,165	81	**7,681**	**227**
1996	2,205	43	2,676	63	480	44	2,148	75	**7,510**	**225**
1997	1,247	18	811	44	309	61	1,257	44	**3,623**	**167**
1998	636	14	602	61	597	68	1,612	50	**3,447**	**193**
1999	1,788	24	1,472	132	5,686	138	1,565	57	**10,511**	**351**
2000	5,046	83	2,253	114	17,707	243	2,319	58	**27,325**	**498**
2001	6,904	62	3,744	111	25,248	370	6,669	62	**42,565**	**605**
2002	4,210	30	5,353	174	52,000	553	8,735	67	**70,298**	**824**
Total	**25,809**	**327**	**18,124**	**739**	**102,556**	**1,530**	**26,470**	**494**	**172,960**	**3,090**

Source: Energy Information Administration, Form EIA-860.

[78]Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" (2002).

[79]Energy Information Administration, *Electric Power Annual 2001*, DOE/EIA-0348(2001) (Washington, DC, March 2003), Table 2.1.

[80]See, for example, New York Independent System Operator, "Power Alert II: New York's Persisting Energy Crisis" (March 27, 2002); and "Power Alert III: New York's Energy Future" (May 2003), web site www.nyiso.com.

[81]Entergy's open access transmission tariff, filed March 20, 2001, is also available on its OASIS web site, http://oasis.e-terrasolutions.com/OASIS/EES.

[82]EIA collects data on delivery charges and megawatts delivered to unbundled *retail* customers on Form EIA-861, Schedule 4, Part C.

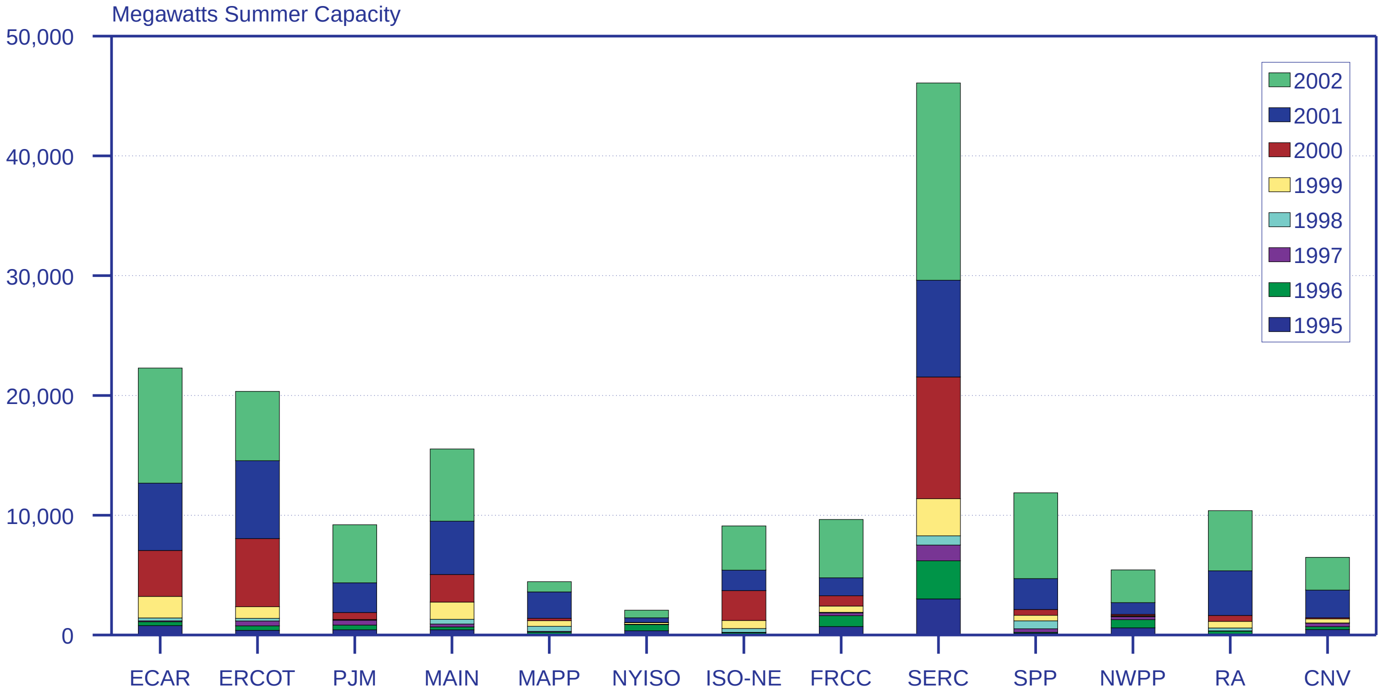
curtailed. Chapter 2 reports that NERC's TLR system records—but does not routinely report—curtailment data, and data are available only for the Eastern Interconnect. Trends in the frequency and size of curtailments are measures of the quality of transmission service.

Bottlenecks

ISOs, transmission owners, and market participants are generally knowledgeable of bottlenecks, although documented analyses of these constraints are available mainly from ISOs. NERC's periodic reliability assessments (see Chapter 2) identify load pockets and bottlenecks. To some extent, NERC's identifications are based on publicly available TLR data; but the analytical basis NERC uses for identifying other bottlenecks is not generally available.

Under contract to DOE, the Consortium for Electric Reliability Technology Solutions (CERTS) surveyed six ISO/RTOs to identify bottlenecks and load pockets in their areas.[83] The results for five of those regions, summarized in Table 17, are representative of the kinds of data available from those organizations. The CERTS study also reported estimates of costs for some of the projects to relieve congestion, as shown in Table 18. It did not report how much those investments would be expected to save.

Figure 7. New Generating Capacity Added by NERC Region, 1995-2002



Source: Energy Information Administration, Form EIA-860.

Table 16. Entergy Transmission Service Rates as of June 1, 2003

Service	Firm		Non-Firm	
	Price	Unit	Price	Unit
Hourly On-Peak (Hour Ending 0700 Through Hour Ending 2200, Monday Through Friday)	—	—	$3.15	Megawatthour
Hourly Off-Peak (All Other Hours)	—	—	$1.50	Megawatthour
Daily On-Peak (Monday Through Friday)	$50.00	Megawatt-Day	$50.00	Megawatt-Day
Daily Off-Peak (Saturday and Sunday)	$36.00	Megawatt-Day	$36.00	Megawatt-Day
Weekly	$252.00	Megawatt-Week	$252.00	Megawatt-Week
Monthly	$1,090.00	Megawatt-Month	$1,090.00	Megawatt-Month
Long Term (1 Year or Longer)	$1,030.00	Megawatt-Month	—	—

Source: FERC staff, compiled from Entergy's OASIS web site.

[83]Consortium for Electric Reliability Technology Solutions, *U.S. Department of Energy Transmission Bottleneck Project Report* (March 19, 2003).

Table 17. Major Bottlenecks in Five ISO/RTO Regions

Region	Widespread Grid Reliability Problems	Risk of Significant Consumer Cost
CAISO	San Diego Area and the San Francisco Peninsula	Path 15
ERCOT . . .	—	South to North Texas and South Texas to Houston
NYISO	—	Central East, Leeds-PV and New York City/Long Island Cable Interface
ISO-NE . . .	Southwest Connecticut to Norwalk, Northeast Massachusetts/Boston Area, and Northwest Vermont	—
PJM	—	Northwest Pennsylvania, West of Washington, DC, Delmarva Peninsula, West and East 500-kV Interface

Source: Consortium for Electric Reliability Technology Solutions, *U.S. Department of Energy Transmission Bottleneck Project Report* (March 19, 2003).

Table 18. Estimated Project Costs for Partial Relief of Congestion

Region	Project	Estimated Cost (Million Dollars)
CAISO	Path 26	306
	Imports to San Diego	252
ERCOT . . .	Two 345-kV lines from West Texas to North Texas	140
MISO	Substantially increase bulk power transfer capability	7,000
	Gains Substation: add a second 345/138-kV transformer bank needed to serve load growth in the area of Grand Rapids, Michigan	7
NYISO	Marcy-New Scotland 345-kV circuit: line originally built for 765 kV could be converted from single to double circuit	75
	Rebuild two 115-kV lines out of Leeds to 345 kV	225
ISO-NE . . .	Build a 345-kV loop around the southwestern Connecticut area (Phase 1 and 2)	600
	Reinforce northwest Vermont load pocket	125
PJM	Add 500/230-kV transformers at Doubs Substation (Northwest of Washington, DC)	22

Source: Consortium for Electric Reliability Technology Solutions, *U.S. Department of Energy Transmission Bottleneck Project Report* (March 19, 2003), p. 17.

Many transmission bottlenecks cannot be identified with TLR data, for a variety of reasons:

- TLRs are not used to manage congestion in the West.
- A TLR may indicate overbooking rather than a physical limit (overbooking is mainly a reflection of the limits to accurate forecasting of transmission requirements).
- Systems trying to facilitate trade may attempt to operate close to their security limits, and systems not encouraging trade may understate how much transmission capacity is available.
- TLRs have not been exercised in the Southeast but are common in the Midwest. Commentators disagree on the reasons for the differences.[84]

Congestion Costs and Revenues

Congestion costs and revenues are measured in at least three ways. System redispatch cost is the increase in total system operating cost due to congestion to meet a fixed level of demand. Redispatch costs are typically captured in *uplift charges*. Mainly these charges occur because higher cost, but better located, generators must be run to get around transmission constraints. The *economic cost* of congestion is the loss in net benefit, which is the same as uplift cost when demand does not depend on price. *Congestion revenue* is the difference between the prices at the sending and receiving ends times the volume of flow on the line. Congestion revenue is analogous to a transportation charge but is in fact a particular kind of scarcity rent. The location-specific prices needed to calculate congestion revenues are generally available for only a few areas, notably the northeastern ISOs. Several organizations have reported the aggregate of some redispatch costs and congestion revenues.

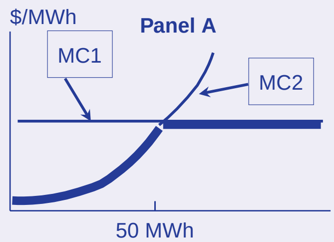
It is rarely necessary to curtail generation under locational prices, because locational prices equate supply and demand in such a way that all transmission limits are met, and they are adjusted in real time in response to system conditions. In the rest of the Eastern Interconnection, service curtailments are used to enforce transmission limits. Thus, observed wholesale prices (when available) do not reflect current transmission constraints: the prices net of transmission charges in the sending area are too high and those in the receiving area are too low. The congestion revenue (observed price

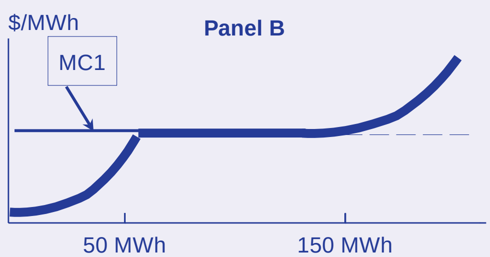
[84]See, for example, L. Canto et al., "Beware Transmission Data—Often They Are Not What They Seem To Be" (Cambridge Energy Research Associates, June 2003).

Redispatch Costs, Congestion Revenues, and Congestion Cost

Redispatch costs, congestion revenues, congestion cost (loss of producers' and consumers' surplus), and uplift costs are caused by constraints on the transmission grid's ability to move power from lower to higher cost areas. The following examples illustrate those concepts.

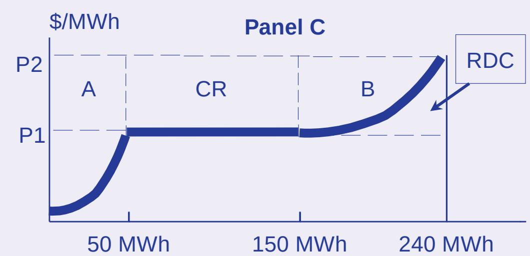
Panel A shows two regional supply curves (marginal cost curves, MC1 and MC2); the thick line is the market supply curve. For simplicity, assume all demand is in Region 2. If there were a limit on power transfers between Regions 1 and 2 of 100 MWh, the aggregate supply curve in Region 2 would be that shown in Panel B. Up to 50 MWh, Region 2 meets its demand with its lowest cost generators; for demand levels up to 150 MWh, those generators are supplemented with imports from Region 1.



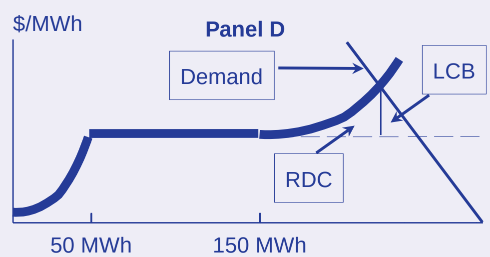


When demand exceeds 150 MWh, for example 240 MWh as shown in Panel C, imports cannot be increased, and Region 2 has to run its higher cost generators, illustrated by the upward sloping curve. If there were no transfer limit, the supply curve in Region 2 would extend the flat section between 50 MWh and 150 MWh indefinitely. Redispatch cost is the difference between the lowest cost of meeting demand with and without the line constraint. When demand is fixed, redispatch cost is the economic cost of congestion. Redispatch cost is shown in Panel C as the area RDC.

Congestion causes consumer expenditures to increase by more than redispatch costs. Marginal cost in Region 2 is *P2* and marginal cost in Region 1 remains at *MC1* = *P1*. In a competitive market, price equals marginal cost. Congestion, together with marginal cost pricing, causes consumer expenditures to grow from *P1* x 240 in the unconstrained case to *P2* x 240, for an increase of (*P2* - *P1*) x 240. As shown in Panel C, the additional expenditures go to generators as increased profit (areas A and B) and compensation for redispatch costs (area RDC). The remaining portion of the increased expenditures goes to transmission owners (or holders of financial transmission rights) as congestion revenues, indicated by area CR, which is the price difference times the flow, (*P2* - *P1*) x 100.



When demand is sensitive to price, congestion reduces the benefits from consuming electricity. Because congestion increases the price of electricity, customers consume less and forgo the benefits of maintaining their electricity use. The economic cost of congestion is the sum of lost consumer benefits and redispatch costs. Those are shown in Panel D as the sum of the areas under RDC (redispatch cost) and LCB (lost consumer benefit).



Uplift charges are the specific fees that systems use to compensate generators for agreeing to be redispatched. How the amount of these uplift charges is determined varies. In the United Kingdom's original pool, generators who are not allowed to produce as much as they would like at the uniform system price are paid an estimate of their forgone profit; those required to produce more at the uniform price are paid to cover their additional costs. Whatever cost/profit/loss scheme is used to compensate generators, the increased revenue from customers is more than adequate to fund the payments.

difference times flow) calculated with observed prices is too low. In an attempt to correct for the understatement of congestion revenue, FERC and the New York ISO have estimated system redispatch costs in the receiving area, then added the estimate to observed congestion revenue. Table 19 summarizes estimates from four ISOs for their areas, and from FERC for the Eastern Interconnection.

Except for the FERC study cited above, official data do not report estimates of redispatch costs, congestion costs, or congestion revenues outside the ISOs. The estimates available for ISOs are mostly an incomparable collage of uplift charges, redispatch costs, congestion revenues, and a total consisting of some redispatch costs and some congestion revenues.

Seams Costs

There are no official data, except possibly for the ISOs and RTOs, that show the actual costs (direct and indirect) uniquely associated with moving power across control or ownership boundaries. Price differences between the sending and receiving areas may reflect, but do not identify, the particular costs of crossing boundaries.

Economic Trade and Regional Price Differences

Economic trade is undertaken to profit from price differences between areas. The basic data for documenting economic trade are wholesale price differences and the corresponding trade flows.

Wholesale trade is a mix of very short-term and long-term transactions. Most wholesale trade occurs in private markets, and the prices are not publicly available.[85] Table 20 shows EIA data on sales for resale— essentially, wholesale trade. In the 6 years following FERC Order 888, wholesale trade on the part of utilities, IPPs, and combined heat and power generators increased by 65 percent, at a continuously compounded growth rate of 8.4 percent per year.

Northeastern ISOs and California have public real-time markets for wholesale energy and publicly report prices. The northeastern ISOs also have day-ahead markets with publicly reported prices. As shown in Table 21, spot markets ("real-time" markets) are an important source of supply in the northeastern ISOs.

PJM reports relevant price and power flow data for its trade with the New York ISO. About 85 percent of PJM's

Table 19. Summary of Congestion Costs Reported by ISOs and FERC

Region	Period	Congestion Costs (Million Dollars)	Cost Calculation Method
PJM [1]	1999	53	Congestion revenues
PJM [1]	2000	132	Congestion revenues
PJM [1]	2001	271	Congestion revenues
PJM [2]	2002	430	Congestion revenues
ISO-NE [3].	5/1999-4/2000	99	Uplift charges[a]
ISO-NE [3].	5/2000-4/2001	120	Uplift charges[a]
ISO-NE [4].	2003	50-300	System redispatch payments
CAISO [5]	2000	391	Congestion revenues
CAISO [5]	2001	107	Congestion revenues
CAISO [6]	2002	42	Congestion revenues
NYISO [7]	2000	1,240	System redispatch payments + congestion revenues
NYISO [7]	2001	570	System redispatch payments + congestion revenues
NYISO [8]	2000	517	Congestion revenues
NYISO [8]	2001	310	Congestion revenues
NYISO [9]	2002	525	Congestion revenues
FERC [10]	6/2000-8/2000	891	System redispatch payments (partial) + congestion revenues

[a]ISO New England's congestion cost calculation method was modified in March 2003.

Sources: [1] PJM Interconnection, *State of the Market Report 2001*; [2] PJM Interconnection, *State of the Market Report 2002*; [3] ISO New England (ISO-NE), *Annual Markets Report*; [4] ISO New England, *RTEP02*; [5] California Independent System Operator (CAISO), *Market Analysis Reports*; [6] CAISO, *2002 Annual Report on Market Issues and Performance*; [7] *New York Congestion and Physical Constraint Cost Estimates*; [8] *2001 Annual Report on the New York Electricity Markets*; [9] *2002 State of the Market Report: New York Electricity Markets*; [10] Federal Energy Regulatory Commission (FERC), *Electric Transmission Constraint Study*. Detailed source citations are provided in the report from which this table was adapted: B.C. Lesieutre and J.H. Eto, *Electricity Transmission Congestion Costs: A Review of Recent Reports* (October 2003), DOE Contract No. DE-AC03-76SF0098.

[85]FERC's new "Electric Quarterly Report" (EQR) collects prices associated with individual wholesale trades. It may be possible to use those data to estimate market prices for specific regions. In addition to volumes, EIA collects annual data on revenues from sales for resale. Dividing revenue by volume yields a volume-weighted average annual price, or the same thing, average revenue for sales for resale.

gross imports and 93 percent of its exports occur in the real-time market. Differences in spot market prices at the borders are clearly appropriate for valuing trade opportunities.[86] In addition to spot prices, PJM reports net exports to New York. Because both have locational prices, it is possible to calculate the differences between the PJM and New York market prices at the borders and to associate price differences with power flows.

Table 20. Wholesale Electricity Trade (Sales for Resale), 1990-2002
(Thousand Megawatthours)

Year	Sales for Resale
1990	1,115,946
1991	1,250,314
1992	1,284,273
1993	1,387,137
1994	1,387,966
1995	1,495,015
1996	1,656,090
1997	1,838,539
1998	1,914,916
1999	1,977,753
2000	2,325,652
2001	2,893,382
2002	2,747,015

Source: Energy Information Administration, *Electric Power Annual 2001*, p. 36, and *Electric Power Annual 2002*, p. 34. Includes utilities, IPPs, and combined heat and power generators; excludes marketers.

During 2002, monthly exports to the New York interface ranged from about 100,000 megawatthours in June, to more than 1,500,000 megawatthours in November. Importantly, the volume of exports generally increases as the monthly average hourly difference between the New York and PJM prices—the price differential—increases. Figure 8 shows the export volume to New York and the average hourly price differential for 2002. That exports increase along with the price differential suggests that competition is working to some extent. It does not explain why there is a significant price differential.

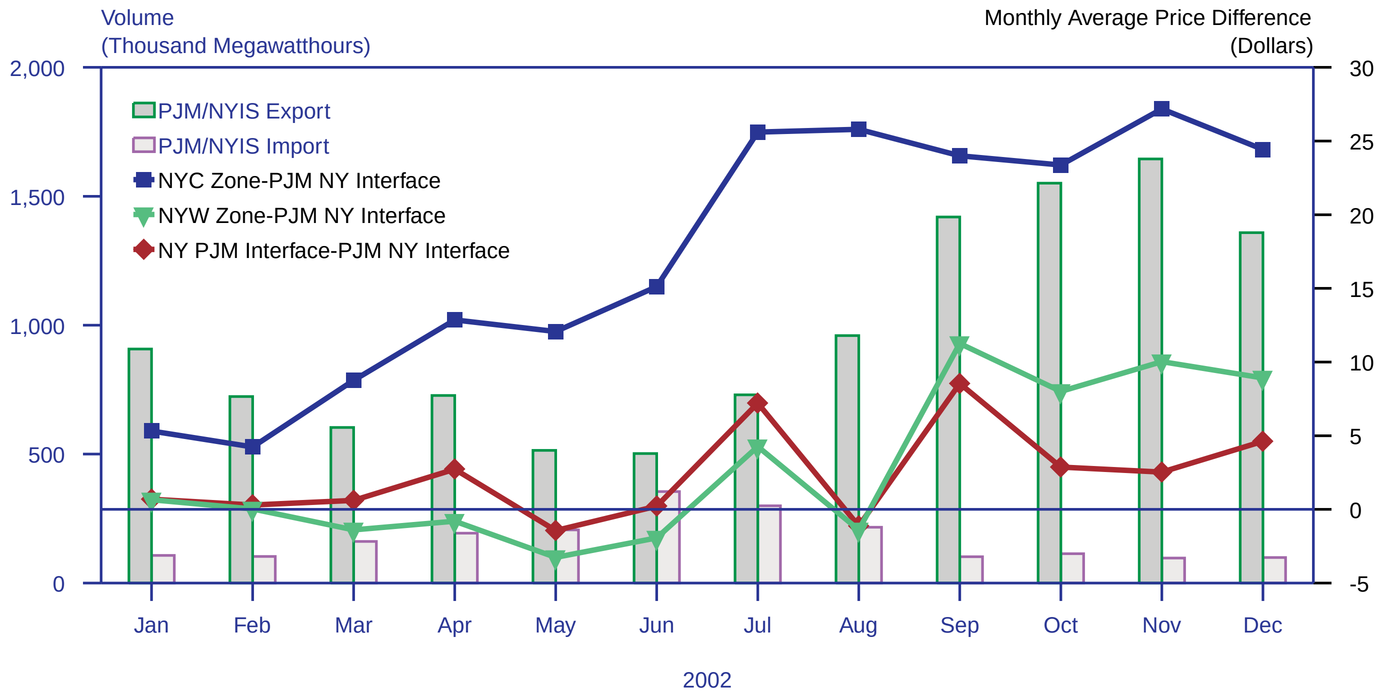
The data do not support similar displays for other ISOs. California's adjacent markets do not report market prices in official data. ERCOT does not trade outside its boundaries. New England and New York have

Table 21. Spot Market Sales as a Percentage of Total Demand, 1999-2002

Year	New England	New York	PJM
1999	13[a]	—	15
2000	23	41	18
2001	24	47	21
2002	32[b]	48	—

[a]May-December.
[b]January-November.
Sources: ISO New England, *Monthly Market Report* (December, 1999-2002); New York Independent System Operator, *Monthly Report* (December, 2000 and 2002); PJM, *State of the Market Report* (1999-2001).

Figure 8. Price Differential and NYISO Export Volume, January-December 2002



Source: PJM, *State of the Market Report* (2002), p. 67.

[86]PJM Interconnection, "2002 State of the Market," p. 62.

substantial trade with Canada at negotiated prices. New England trades with New York but, until recently, did not use locational prices. Consequently, the "at-the-border" price differences do not necessarily reflect economic values. There are no official wholesale market price data for PJM's trading partners outside New York.

Other than those reported by ISOs, wholesale electricity prices are not publicly available. EIA does not collect data on wholesale electricity prices except as a volume-weighted average price (total revenue divided by volume sold), which does not accurately reflect actual market prices. The volume-weighted calculation includes data from transactions under long-term contracts that do not reflect current market prices, and it does not incorporate the impact of ongoing changes in market prices, including hourly, daily, and seasonal swings.[87] FERC is now attempting to collect the prices associated with individual spot markets and long-term contracts in its "Electric Quarterly Reports."[88] It is too early to tell whether the data can yield good approximations of market prices in areas lacking formal markets. Outside the ISOs, official power flow data are of uneven quality.

International import data illustrate some of the problems in estimating power flows across boundaries. Canada has long been an important supplier of low-cost electricity to the United States, much of it generated from hydropower, but it is not clear how much has been supplied. Data on international electricity trade with Canada (and Mexico) are collected and reported on an annual basis by DOE on Form FE-781R, "Annual Report of International Electrical Export/Import Data," and by Canada's National Energy Board (NEB). The NEB collects information directly from market participants, many of whom trade power under long-term contracts utilizing Presidential Permits. As illustrated in Table 22, the volumes reported by NEB generally are greater than those reported by DOE, and the differences are too large to be explained by differences in metering.

Except for PJM and New York, official data cannot be used to show the extent or growth of economic trade. Outside the northeastern ISOs it is not possible to show that wholesale price differences are narrowing.

Filling the Information Gaps

With the important exception of wholesale price and quantity, much of the data needed to evaluate the transmission grid's support of markets is already being collected. EIA collects comprehensive data on generators, including those planning to connect to the grid. Those data are indispensable for analyzing the potential supply of electricity, generator entry to the market, and market shares (see Chapter 5). OASIS data are critical to evaluating access, transmission tariffs, and the quality of service (firm or interruptible, point-to-point or network). NERC has data on power flows across the high-voltage grid and on curtailments. The ISOs are reporting congestion.

OASIS and NERC data are either unusable, unavailable to the Federal Government on a routine basis, or both. The OASIS data are scattered across dozens of web sites, are neither edited nor archived, and are not in useable form. NERC's power flow and curtailment data are not routinely available for the government's monitoring of wholesale trade. Congestion data, trade flows, and market price differentials are only available for the ISOs. Each ISO defines and makes the data available (or not) differently. Table 23 provides suggestions for modifying existing data collection forms and web sites to make them more applicable to the Federal Government's monitoring responsibilities.

Table 22. Comparison of Electricity Transactions Reported by the U.S. Department of Energy (DOE) and Canada's National Energy Board (NEB), 1997-2001
(Billion Kilowatthours)

Year	U.S. Imports from Canada		U.S. Exports to Canada		Net U.S. Imports	
	DOE	NEB	DOE	NEB	DOE	NEB
1997	47.83	43.06	15.56	7.47	32.37	35.59
1998	45.41	39.50	15.95	11.68	29.46	27.82
1999	38.56	42.91	12.28	12.95	26.28	29.96
2000	43.68	48.52	11.24	12.68	32.44	35.84
2001	31.12	38.40	12.36	16.10	18.77	22.30

Sources: **DOE:** U.S. Department of Energy, Form FE-781R, "Annual Report of International Electrical Export/Import Data." **NEB:** National Energy Board, web site www.neb.gc.ca/stats/elec/index_e.htm.

[87]These distortions frequently go unrecognized. See, for example, L. Lynch, "An Unfair Jolt to Consumers," *San Francisco Chronicle* (December 12, 2003), in which the figure description identifies average revenue as price; and U.S. General Accounting Office, *Electricity Restructuring*, GAO-03-586, Appendix 1, p. 49, which asserts that Form EIA-826 ". . . is the only timely source of information on the price and volume of power sold . . . ." The reference is to volume-weighted price revenue, not market price.

[88]Federal Energy Regulatory Commission, *Revised Public Utility Filing Requirements*, Order No. 2001, Final Rule, 18 CFR Parts 2 and 35 (April 25, 2002).

Nationwide data on seams costs could only be obtained with a new data collection. Data on cost and quality of transmission service could be obtained either by modifying the data that utilities are required to report on OASIS or by adding reporting categories to existing EIA forms.

Some of the data needed to monitor the transmission grid's support of markets may become available in the course of meeting other needs. The government's ability to analyze the physical basis for load pockets and bottlenecks, and to determine what investments would mitigate them, depends on its having access to high-quality power flow models. The government may decide to build and maintain such models for reliability or national security reasons and make them available for public policy analysis. If so, there would be no need for additional, specialized models to study load pockets and bottlenecks.

Outside the ISOs, spot market prices and associated quantities, including interregional trade flows, are not available. FERC's new EQR does record transaction prices and quantities for "long term" and "short term" transactions, but they are not the same as the spot market prices reported by the ISOs. It is too early to know whether the EQR data can yield accurate estimates of market prices comparable to those in the ISOs. If not, a new collection would be required to obtain wholesale prices and associated quantities. Significant research and effort would be required in order to collect the information.

Table 23. Transmission and Wholesale Power Market Data: Possible Changes to Existing Forms

Information Need	Form	Needed Changes	Comment
1. Access time series data by provider.	OASIS	Consolidate, edit, and archive all data required on OASIS in a single database.	
2. Transmission service offerings and actual rates.	OASIS	As above.	
3. Cost and time required for generator connection.	EIA-860	Report how much generator paid for grid reinforcements, direct (other) connection costs, and the date of the initial connection request.	For newly activated generators, add questions to Schedule 3, Part B, Line 4.
4. Load-serving entity cost and quality of transmission service.	EIA-861	Report percent of supply covered by long-term contracts, percent covered by firm service (or financial transmission rights), transmission service expense, and curtailments (megawatthours) of firm and non-firm service in past year.	Schedule 2, Part B.
5. Generator cost and quality of transmission service.	EIA-906	Report paralleling that of load-serving entities (see above).	
6. Congestion costs, trade flows and price differentials.	ISO web sites	FERC and ISOs define data elements the same way across ISOs and report data to FERC.	None of this information is available for analyzing the effect of restructuring policy outside the ISOs.

5. Wholesale Competition

Introduction

Chapter 4 reviewed information relevant to the electricity transmission grid's support of wholesale markets. This chapter considers the information available to determine whether wholesale markets are competitive. Competitive markets are desirable because they promote the efficient allocation of resources.[89] The Federal Government is responsible for approving utility mergers and for enforcing antitrust law, as well as wire fraud and conspiracy statutes incident to recent prosecutions for electricity market manipulation.

Somewhat surprisingly, competitive wholesale electricity prices are also necessary for properly valuing congestion revenues and, thereby, providing signals for transmission investment and new generator location. Congestion can be reduced by investments in transmission capability and by locating new generators to relieve bottlenecks. When energy prices are competitive, the transmission price (difference in energy price at either end of a line) is the marginal benefit (savings) from relieving congestion. Consequently, when wholesale prices are competitive, the congestion charge is appropriate for signaling the (marginal) need for investment and for guiding the location of new generation. The Federal Government's interest is not to determine where lines and generators should be located but rather to give State government and private decisionmakers information about the resource consequences of their decisions.

The next section, "Measures of Wholesale Competition," presents conventional statistics that have been accepted by Federal courts for describing competitive markets. The section that follows, "Data on Wholesale Competition," identifies the Federal Government's capabilities for monitoring and evaluating wholesale competition in the electricity industry. The chapter concludes with a section on "Filling the Information Gaps," which discusses how gaps in existing data collections might be filled.

Measures of Wholesale Competition

At any particular time, competitive markets are characterized by a large number of suppliers vying to sell to a large number of informed customers. When there are many buyers and sellers, each of whom is small relative to the market, no one has significant power over price. In those circumstances, the market price is one that causes demand to equal supply, and price approximately equals the cost of producing the last unit sent to market—the marginal cost.[90] Price also equals the marginal benefit received by the last customer willing to make a purchase. A supplier has market power when he can sustain a price that is significantly above marginal cost.

Economists often use the notion of long-run competition to capture the idea that free entry and exit of competitors would eliminate excessive profits. In classical analysis, that would mean not only that price would equal marginal cost but also that price would equal minimum average cost. Minimum average cost includes a normal rate of return on capital. Modern formulations of the idea of long-term equilibrium refine this idea to consider "lumpy" capacity increments, the number of ideally sized firms relative to the market, and technical problems in defining least average cost for some production processes.[91] Without free entry and exit of independent firms, price could equal marginal cost (an efficiency condition), but profits would be supernormal, indicating under-investment in the industry.

Number of Competitors, Concentration Ratios, and New Entry

The number of firms serving a regional market, their market shares, and market share indices—especially the Herfindahl-Hirschman Index (HHI)—are well-established indicators of a competitive industry.[92] These measures assume that the relevant market can be identified. The difficulty in calculating market shares and HHIs in the electricity industry is that market boundaries are not

[89]Efficient in the sense that a competitive wholesale power market would minimize the social cost of meeting consumers' electricity demands, and those demands would reflect the value to consumers of consuming electricity relative to the value of consuming other goods. Stated differently, competition has the potential to maximize the net benefit from electricity consumption, less the costs of its production and delivery.

[90]Price might not equal marginal cost when some production inputs are "lumpy."

[91]See, for example, A. Mas-Colell, M.D. Whinston, and J.R. Green, *Microeconomic Theory* (London, UK: Oxford University Press, 1995), pp. 334-341.

[92]See U.S. Department of Justice and U.S. Federal Trade Commission, "Horizontal Merger Guidelines," Section 1—Market Definitions, Measurement and Concentration (issued April 2, 1992; revised April 8, 1997), web site www.usdoj.gov/atr/public/guidelines/horiz_book/hmg1.html.

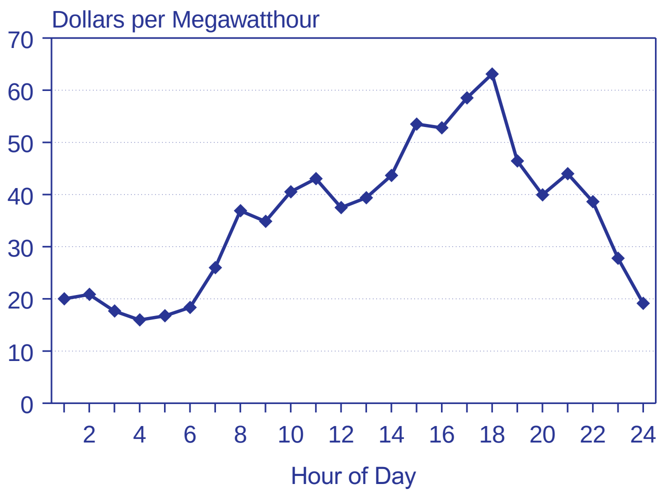
obvious, and establishing boundaries generally requires electrical models. As discussed in Chapters 2 and 4, the Federal Government does not maintain reference electrical models sufficient for delineating regional markets. While the courts pay attention to the HHI, they also consider many other factors before concluding that a firm is exercising market power.

Price Compared to Marginal Cost

Market price compared to marginal cost is a litmus test for competition: wholesale price sustained above the marginal cost of the last generator dispatched can indicate market power. This comparison, called the Lerner index, is variously calculated as the ratio of price to marginal cost, the percent markup over marginal cost, or the markup as a percentage of price.[93] Accurately estimating and interpreting the Lerner index is often a challenge.

To make a valid comparison, reference prices and marginal costs must refer to the same period of time. This is important in the electricity industry because prices typically fluctuate significantly during the day. An example of hourly prices at the Pennsylvania-New Jersey-Maryland Interconnection (PJM), as shown in Figure 9, is illustrative of the magnitude of price variation.

Figure 9. Average PJM Hourly Wholesale Price on July 16, 2002



Source: Source: Data from web site www.pjm.com; markets, energy, real-time, monthly real-time LMP, file 200207-rt.csv, load-weighted average prices.

Accurate estimates of marginal cost are also critical to the results. As pointed out by Timothy Brennan, many power market studies have used average variable cost rather than true marginal cost, thus overstating the extent of market power and perhaps influencing regulators to enforce artificially low price ceilings.[94]

Selecting the right marginal cost to use in the Lerner index also requires care. When transmission is unconstrained, the available generators are ranked in order of their marginal costs from least to most costly. The marginal cost of the *last* generator needed to meet demand is the relevant marginal cost in the Lerner comparison.[95]

In actuality the transmission grid is at times congested—power cannot be delivered as desired. PJM again provides an example, as shown in Table 24. When the system is congested, generators are recruited "out of merit order" to stay within security limits (see Chapter 2 for a discussion of security limits). A congested system segments into submarkets, all operating simultaneously. Sorting out which generator's marginal costs to pair with observed locational prices requires both an electrical model and information on the amount of demand and where it is located.

Areas that routinely find themselves in high-priced submarkets are called "load pockets." Because these areas have limited recourse to outside suppliers, generators within load pockets are well placed to increase price substantially above marginal cost.

Table 24. PJM Congested Hours (Real Time) in 2002

Month	Hours Congested
January	245
February	79
March	120
April	263
May	596
June	664
July	505
August	540
September	595
October	540
November	533
December	550

Source: Source: PJM Interconnection, *State of the Market Report 2002*, Figure A-15, p. 165.

93 A. Lerner, "The Concept of Monopoly and the Measurement of Economic Power," *Review of Economic Studies*, Vol. 11 (1934), pp. 157-175.

94 T.J. Brennan, "Mismeasuring Electricity Market Power," *Regulation* (Spring 2003), pp. 60-65.

95 It can happen that market demand is met at exactly the maximum capacity of the most expensive generator. In that case a competitive price is consistent with any marginal cost between that of the last generator recruited and the generator required to meet any small additional demand. See S. Stoft, *Power System Economics* (New York, NY: John Wiley/IEEE Press, 2002), for a detailed discussion of these issues. For the Lerner test to provide the correct answer, all generators able and economic to run at the time the comparison is made must be available for dispatch. If low-cost generators were withheld from the market, price would equal marginal cost, but market prices would be above the competitive level.

Withholding and Manipulation of Transmission Markets

Concentration ratios and Lerner indices shed little light on how market participants can sustain artificially high prices. They do not account for the kinds of capacity withholding and grid manipulation that FERC has observed in electricity markets.[96] Withholding appears to have been one way in which generators were able to increase prices during the electricity crisis in California. FERC sees withholding as sufficiently important that it has developed a pivotal supplier test, which attempts to identify generators whose absence would be enough to result in significant price increases.[97] The data needed to calculate Lerner indices are adequate to identify pivotal suppliers.

Enron showed how generators might take advantage of market rules to manipulate transmission markets and increase their profits. To the extent that gaming impacts prices, the Lerner index may indicate that something is amiss; however, it will not detect strategies that only shift profits.

Joskow and Tirole make a more subtle point about the ownership of financial transmission rights (congestion revenue rights). Holders of these rights are paid the congestion revenues associated with the constrained lines covered by their rights.[98] Joskow and Tirole conclude:

> *The possession of financial rights by a producer in the importing region or by a consumer in the exporting region aggravates their market power, since financial rights give them an extra incentive to curtail their output or demand to make the rights more valuable.*[99]

Consequently, in those areas that use congestion rights, data on their ownership could be important.

Limits on Market Power

Firms with market power do not have an unlimited ability to charge whatever they want to charge. New entrants and the threat of new entrants into the market have a constraining impact on market power in many industries. To the extent that new competitors can enter quickly at low cost, incumbent firms are dissuaded from exercising market power. If competitors actually enter in response to high prices, they will diminish the price-setting power of incumbents.

Price increases lead to demand reductions in most industries, and if the increases are pronounced, the reductions in demand limit how much suppliers can profitably charge. In the electricity industry, however, there is presently a very limited degree of demand response to price. Essentially all retail customers face fixed prices, and consequently when demand approaches the limits of supply, generators could—absent regulatory intervention—raise prices without fear of losing sales. Regulatory pressure is currently more effective in disciplining prices than is demand response.

The "natural" curbs on market power in the electricity industry are limited, and the transmission grid provides some generators with protection from competition. Both considerations suggest that market prices may be above competitive prices, at least when supplies are short.

Data on Wholesale Competition

Number of Firms and Concentration Ratios

Between FERC and EIA, the Federal Government has a complete list of the larger generators, their capacity, annual production, and ownership. Form EIA-860 is the source for two periodic EIA reports, *Inventory of Electric Utility Power Plants in the United States* and *Inventory of Nonutility Power Plants in the United States*. The coverage of small generators (especially cogenerators) is less complete, but given market boundaries, official data are adequate to identify the competitors and their capacities. EIA also collects data on the output and heat rates of individual generators, which allow calculation of market concentration ratios and the fuel portion of costs, although those data are not publicly available.

Price Compared to Marginal Cost

These comparisons are a basic test of market competition. As explained above, they require data on market prices and quantities, net trade flow, good estimates of marginal cost and, when the grid is congested, an electrical model. ISOs have comprehensive data on market prices, quantities, trade flows, offers to buy and sell, and knowledge of operable units.[100] They can also possess the detailed knowledge necessary to estimate marginal

[96]See, for example, Federal Energy Regulatory Commission, "Final Report on Price Manipulation in Western Markets, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices," Staff Report, Docket No. PA02-2-000 (March 2003).

[97]The test amounts to removing hypothetically some or all of a generator's capacity from the market supply. If that removal would cause price to increase substantially above the competitive level, the generator is said to be pivotal.

[98]The congestion revenues are the difference in the prices at the receiving and sending locations, times the flow guaranteed by the right. When the two prices are the same, there are no congestion revenues.

[99]P. Joskow and J. Tirole, "Transmission Rights and Market Power on Electric Power Networks," *The Rand Journal of Economics*, Vol. 31, No. 3 (Autumn 2000), p. 475.

[100]The market prices that ISOs report are occasionally "mitigated": the ISO rejects the original market price and replaces it with the mitigated price when the ISO concludes that the former is exorbitant.

cost, placing them (or their market monitors) in a good position to compute and interpret Lerner indices.[101]

PJM has released estimates of the Lerner index for its system, reporting the markup over price.[102] In addition to having valid electrical models and comprehensive data on generator availability, offers, production, and demand volumes and locations, PJM had cost data on all units whose construction started before July 9, 1996.[103] PJM calculated the Lerner index for every 5-minute interval and accounted for congestion. PJM has not, however, released the underlying data and models necessary to replicate those results.

PJM reported two estimates of the average markup as a percentage of price. The first, called the "adjusted markup," assumed that PJM's marginal cost estimates were precise. The resulting index averaged 11 percent for 2002, with a maximum of 13 percent (in July) and a minimum of 10 percent. The second assumed that the marginal cost estimates did not incorporate all relevant costs, and PJM increased the marginal cost estimates by 10 percent (presumably to cover such difficult-to-measure items as variable operations and maintenance costs). The result lowered the average markup to 2 percent in 2002, with a maximum of 4 percent in July and a minimum of 1 percent.[104] PJM interprets the results as follows:

> *. . . the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2002 although the evidence is not dispositive.*[105]

Official data for areas outside ISOs are far less precise. On Forms EIA-860 and EIA-423, EIA collects (but does not publicly release) generator fuel costs, heat rates, and similar information for estimating marginal cost. Fuel costs are reported monthly and heat rates tend to be long-term averages. Because a generator's heat rate varies significantly depending on utilization and operating regime (startup, shutdown, etc.), marginal cost estimates based on those data are likely to be imprecise approximations of hourly marginal costs. Hourly data on generation from fossil-fueled and hydroelectric facilities (pumped storage) are not available from EIA.

In comparing price to the marginal cost of serving the wholesale market, it is necessary to know which generators were available at the time the wholesale price comparisons were made. The U.S. Environmental Protection Agency (EPA), through its Continuous Emissions Monitoring System (CEMS), records hourly emissions, and sometimes hourly output, from fossil-fueled generators.[106] The absence of emissions is an indicator that a particular plant is not operating.

Outside ISOs, there are no official hourly market prices. There are commercially available prices at a few "hubs," but it is unclear how closely those prices approximate market prices. If market data showed multiple prices, it would be necessary to have an accurate electrical model to determine whether the differences reflected congestion or something else. As mentioned previously, the Federal Government does not maintain such models. Also, outside the ISOs, official data do not support firm conclusions about the presence or absence of competitive wholesale markets.

Entry

Chapter 3 showed that the Federal Government has comprehensive data on the connection of larger generators to the electricity transmission grid. A large number of independent generators have entered the market since 1999, and official data reflect little about the costs and time lags associated with entry. Further, official data on access are not archived in a form that allows statistical analysis of access availability and quality of service.

Demand-Price Response

The Federal Government collects no data on the amount of consumption that is metered for price response, nor does it routinely collect data on consumer participation and behavior in price-responsive demand programs. ISOs periodically release information about their programs, which, to the extent that relevant data are reported, indicates that demand response is minuscule. The New England ISO, for example, reports on its web site the number of customers signed up for each program and the megawatts (MW) available for response:

> *As of November 1, 2002, there were 248 customers signed up for the load response program providing 195.615 MWs of possible load relief. There are 122.494 MWs in the Class 1 Program and 73.121 MWs in the Class 2 Program.*[107]

[101] Independent researchers have made similar calculations using price data from ISOs. See, for example, S. Borenstein, J. Bushnell, and F. Wolak, *Measuring Market Imperfections in California's Restructured Wholesale Electricity Market*, CSEM WP102 (University of California Energy Institute, June 2002).

[102] Calculated as: (*market price* - *marginal cost*) / (*market price*).

[103] PJM Interconnection, *2002 State of the Market*, p. 28, web site www.pjm.com/markets/market-monitor/reports.html.

[104] *Ibid.*

[105] *Ibid.*, p. 5.

[106] EPA's emphasis is on emissions. Some records show significant generation without any fuel input.

[107] See web site www.iso-ne.com/Load_Response/main.html January 22, 2003.

The total possible load relief is only 0.7 percent of New England's installed capacity in 2000.[108]

Similarly, PJM's *State of the Market* report finds that, "The maximum hourly reduction in load that resulted from PJM programs was 1,833 MWh in 2002."[109] This compares with a maximum daily peak demand of 63,762 MW in 2002. Clearly, demand response is not a counterweight to market power at this time.

Filling the Information Gaps

Outside ISOs, the government does not have the data necessary to monitor and evaluate the competitive status of wholesale electricity markets. Government can subpoena data in response to clear behavioral evidence of anticompetitive behavior or as part of a merger approval, but the subpoena is not a reasonable means of obtaining data for routine monitoring of the market.

If Federal regulators and antitrust officials are satisfied with market share analyses, then the critical need is for high-quality power flow models and associated data described in Chapter 2. That information is required to delineate market boundaries.

If Federal regulators and antitrust officials require Lerner indices for non-ISO areas, significantly more data than are currently available would be needed. Critical data missing are high-frequency wholesale prices, generator output and availability, and demand net of power inflows. High-frequency market-specific wholesale price data would require new data collections.

Hourly generation data from fossil-fueled units would be available if EPA required (rather than just encouraging) generators to report actual generation quantities injected into the grid on the CEMS; however, CEMS does not apply to generation from nuclear units, hydropower (including pumped storage), wind, solar, and geothermal units. Hourly generation data for nuclear and Federal hydropower plants exist, but they are not readily available. Utilities and independent power producers have production data for the other sources; however, neither EIA nor FERC currently collects them. NERC maintains extensive data on generator availability.

Demand by control region is reported hourly on FERC Form 714. As noted in Chapter 2, those data are not disaggregated to individual buses, reporting is incomplete, and the data from different reporters are contradictory. Because hourly net power inflows are not reported, net demand cannot be calculated.

By contrast, ISOs have all the data required to delineate markets within their areas and to compute concentration ratios and Lerner indices.[110] FERC has the power to require that ISO data necessary to gauge competition be made routinely available to government policymakers and analysts, but to date FERC has not issued such a requirement.

Information on demand response to prices could be obtained by adding a new schedule to Form EIA-861. The required information would include potential megawatts metered to record hourly (or higher frequency) consumption and megawatthours charged by time of consumption.

[108]Energy Information Administration, *Electric Power Annual 2000,* DOE/EIA-0348(2000) (Washington, DC, August 2001), Volume II, Table 3.

[109]PJM Interconnection, *2002 State of the Market,* p. 37, web site www.pjm.com/markets/market-monitor/reports.html.

[110]If the statistics indicate noncompetitive pricing, special-purpose data collections can be employed to determine how (withholding, manipulation of transmission markets, etc.) market participants are thwarting efficient pricing.

Appendix A
Federal Data Collections

FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," is filed with the FERC and can provide DOE/EIA with a comprehensive listing of transmission data for investor-owned utilities. Data from this form include line location, voltage rating, structure type, conductor information, number of circuits, and land and construction costs. This form also delineates whether the data are related to either old or new transmission lines. The FERC Form 1 is one of the most useful data sources for investor-owned utilities with critical information related to transmission line identification, ownership, physical/electrical characteristics, and cost.

FERC Form 714, "Annual Electric Control and Planning Area Report," is filed annually by electric utilities or groups of electric utilities that operate a control area with annual peak demand greater than 200 megawatts. Information related to transmission reported on this form includes adjacent control area names, control area interconnection line/bus names, control area scheduled and actual interchanges, and corresponding line/bus voltage.

FERC Form 715, "Annual Transmission Planning and Evaluation Report," is filed annually by any transmitting utility that operates network (not radial) transmission facilities at or above 100 kV. In the case of joint ownership, only the operator of the facilities must complete the FERC Form 715. FERC requires each transmitting utility to submit in electronic form its base case power flow data if it does not participate in the development and use of regional power flow data. A respondent that participates in the development and use of regional power flow studies must either submit the regional base case power flow data or designate the regional organization to submit such data. Also included in the submittal are transmission system maps and one-line diagrams, a detailed description of the transmission planning reliability criteria used to evaluate system performance, and a detailed evaluation of the respondent's anticipated system performance as measured against its stated reliability criteria, using its stated assessment practices.

Form EIA-411, "Coordinated Bulk Power Supply Program Report," is intended to provide DOE/EIA with an industry-wide source of information regarding regional supply and demand projections for a 5-year advance period. The utilities and other electricity suppliers submit their Form EIA-411 information to their respective NERC regional councils by April 1 of each year. NERC collects the data from the regional councils and then provides the data to DOE/EIA. The data reported to DOE/EIA in this form consist of a comprehensive list of supply and demand figures for each NERC regional council. Also included in the Form EIA-411 are transmission line maps, proposed transmission line data (including location, line length, expected service date, kV rating, and ownership) and load flow studies. Finally, the Form EIA-411 provides information on capacity sales and purchases across regions.

Form EIA-412, "Annual Electric Industry Financial Report," is filed annually by municipal and Federal utilities and includes information similar to the FERC Form 1. Data from the Form EIA-412 include line location, voltage rating, structure type, conductor information, number of circuits, and land and construction costs. This form also delineates whether the data are related to either old or new transmission lines. The form contains very useful data from municipal utilities with critical information related to transmission line identification, ownership, and physical/electrical characteristics. Additionally, the form initiated collection of transmission data from cooperatives that own generation, beginning with the 2001 annual data.

Form EIA-417, "Emergency Incident and Disturbance Report," is filed at each occurrence of a loss of transmission ability by those electric utilities that operate a Control Area, and/or Reliability Coordinators, or other electric utility, as appropriate. The type, cause, and extent of the emergency are reported, as well as the response and the eventual resolution of the emergency. Most of the types of emergencies reported on this form occur on local distribution systems rather than on transmission systems.

Form EIA-860, "Annual Electric Generator Report," collects data on the status of existing U.S. electric generating plants with a nameplate rating of 1 megawatt or greater, and those plants scheduled for initial commercial operation within 5 years of the filing of the form. Data are collected at the generator level, and include fuel source. Respondents include both those in the electricity generation industry and those in other industries (such as manufacturing) that also generate electricity.

Form EIA-861, "Annual Electric Power Industry Report," reports on the status of electric power industry participants involved in the generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico. Electric power industry participants include electric utilities, wholesale power marketers (registered with the FERC), energy service providers (registered with the States), and electric power producers. Data collected include information on owned or leased transmission lines, purchases (sales) of transmission services on other electrical systems, wholesale power marketing, retail power marketing, and demand-side management (DSM) programs.

Form FE-781R collects electrical import/export data from entities authorized to export electric energy, and those authorized to construct, connect, operate or maintain facilities for the transmission of electric energy at an international boundary as required by 10 CFR 205.308 and 205.325. Actual imports and exports of electricity are reported in detail by month. Export authorization holders primarily report quarterly, while Presidential Permit holders report annually. DOE uses these data to track electricity being imported into the United States.

RUS Form 7, "Financial and Statistical Report for Electrical Distribution Borrowers," is filed annually by current RUS borrowers that do not own generation. Data from this form includes miles of transmission lines and transmission operating and maintenance expenses. The information included in the RUS Form 7 is somewhat limited in detail and scope and does not provide as much critical data as the preceding non-RUS forms.

RUS Form 12, "Financial and Statistical Report for Power Supply Borrowers and Electric Distribution Borrowers with Generating Facilities," is filed annually by current RUS borrowers that own generation. Data from this form includes miles of transmission lines by voltage, limited substation information, and transmission operating and maintenance expenses. The information included in the RUS Form 12 is also somewhat limited in detail and scope and does not provide as much critical data as the preceding non-RUS forms.

Acronyms

DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GW, GWh	Gigawatt, Gigawatthour
IPP	Independent power producer
kW, kWh	Kilowatt, Kilowatthour
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MECS	Michigan Electrical Coordinated Systems
MW, MWh	Megawatt, Megawatthour
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
OASIS	Open Access Same Time Information Service
PJM	PJM Interconnection
RTO	Regional Transmission Organization
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
WECC	Western Electricity Coordinating Council

Electricity Glossary

Alternating Current (AC): An electric current that reverses its direction at regularly recurring intervals.

ACE: Area Control Error in MW. A negative value indicates a condition of under-generation relative to system load and imports, and a positive value denotes over-generation.

Active Power: See "Real Power."

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

AGC: Automatic Generation Control is a computation based on measured frequency and computed economic dispatch. Generation equipment under AGC automatically responds to signals from an EMS computer in real time to adjust power output in response to a change in system frequency, tie-line loading, or to a prescribed relation between these quantities. Generator output is adjusted so as to maintain a target system frequency (usually 60 Hz) and any scheduled MW interchange with other areas.

Apparent Power: The product of voltage and current phasors. It comprises both active and reactive power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Blackstart Capability: The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the bulk electric system.

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Bulk Transmission: A functional or voltage classification relating to the higher voltage portion of the transmission system, specifically, lines at or above a voltage level of 115 kV.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits.

Capacitor Bank: A capacitor is an electrical device that provides reactive power to the system and is often used to compensate for reactive load and help support system voltage. A bank is a collection of one or more capacitors at a single location.

Capacity: See "Generator Capacity" and "Generator Nameplate Capacity (Installed)."

Cascading: The uncontrolled successive loss of system elements triggered by an incident. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Circuit: A conductor or a system of conductors through which electric current flows.

Circuit Breaker: A switching device connected to the end of a transmission line capable of opening or closing the circuit in response to a command, usually from a relay.

Control Area: An electric power system or combination of electric power systems to which a common automatic control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load in the electric power system(s); (2) maintain, within the limits of Good Utility Practice, scheduled interchange with other Control Areas; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area Operator: An individual or organization responsible for controlling generation to maintain interchange schedule with other control areas and contributing to the frequency regulation of the interconnection. The control area is an electric system that is bounded by interconnection metering and telemetry.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Demand: The rate at which electric energy is delivered to consumers or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Also see "Load."

DC: Direct current; current that is steady and does not change sinusoidally with time (see "AC").

Dispatch Operator: Control of an integrated electric system involving operations such as assignment of levels of output to specific generating stations and other sources of supply; control of transmission lines, substations, and equipment; operation of principal interties and switching; and scheduling of energy transactions.

Distribution: The delivery of energy to retail customers.

Distribution Network: The portion of an electric system that is dedicated to delivering electric energy to an end user, at or below 69 kV. The distribution network consists primarily of low-voltage lines and transformers that "transport" electricity from the bulk power system to retail customers.

Disturbance: An unplanned event that produces an abnormal system condition.

Electrical Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included. Note: Due to the issuance of FERC Order 888 that required traditional electric utilities to functionally unbundle their generation, transmission, and distribution operations, "electric utility" currently has inconsistent interpretations from State to State.

Element: Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Emergency: The failure of an electric power system to generate or deliver electric power as normally intended, resulting in the cutoff or curtailment of service.

Emergency Voltage Limits: The operating voltage range on the interconnected systems that is acceptable for the time, sufficient for system adjustments to be made following a facility outage or system disturbance.

EMS: An energy management system is a computer control system used by electric utility dispatchers to monitor the real time performance of various elements of an electric system and to control generation and transmission facilities.

Energy Emergency: A condition when a system or power pool does not have adequate energy resources (including water for hydro units) to supply its customers' expected energy requirements.

Fault: A fault usually means a short circuit, but more generally it refers to some abnormal system condition. Faults are often random events.

Federal Energy Regulatory Commission (FERC): The Federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

Flashover: A plasma arc initiated by some event such as lightning. Its effect is a short circuit on the network.

Flowgate: A single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage.

Forced Outage: The shutdown of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Frequency: The number of complete alternations or cycles per second of an alternating current, measured in Hertz. The standard frequency in the United States is 60 Hz. In some other countries the standard is 50 Hz.

Frequency Deviation or Error: A departure from scheduled frequency; the difference between actual system frequency and the scheduled system frequency.

Frequency Regulation: The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Swings: Constant changes in frequency from its nominal or steady-state value.

Generation (Electricity): The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator: Generally, an electromechanical device used to convert mechanical power to electrical power.

Generator Capacity: The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions.

Generator Nameplate Capacity (Installed): The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

Grid: The layout of an electrical distribution system.

Grid Protection Scheme: Protection equipment for an electric power system, consisting of circuit breakers, certain equipment for measuring electrical quantities (e.g., current and voltage sensors) and devices called relays. Each relay is designed to protect the piece of equipment it has been assigned from damage. The basic philosophy in protection system design is that any equipment that is threatened with damage by a sustained fault is to be automatically taken out of service.

Ground: A conducting connection between an electrical circuit or device and the earth. A ground may be intentional, as in the case of a safety ground, or accidental, which may result in high overcurrents.

Imbalance: A condition where the generation and interchange schedules do not match demand.

Impedance: The opposition to power flow in an AC circuit. Also, any device that introduces such opposition in the form of resistance, reactance, or both. The impedance of a circuit or device is measured as the ratio of voltage to current, where a sinusoidal voltage and current of the same frequency are used for the measurement; it is measured in ohms.

Independent System Operator (ISO): An independent, Federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.

Interchange: Electric power or energy that flows across tie-lines from one entity to another, whether scheduled or inadvertent.

Interconnected System: A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection: Two or more electric systems having a common transmission line that permits a flow of energy between them. The physical connection of the electric power transmission facilities allows for the sale or exchange of energy.

Interface: The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

ISAC: Information Sharing and Analysis Centers (ISACs) are designed by the private sector and serve as a mechanism for gathering, analyzing, appropriately sanitizing and disseminating private sector information. These centers could also gather, analyze, and disseminate information from Government for further distribution to the private sector. ISACs also are expected to share important information about vulnerabilities, threats, intrusions, and anomalies, but do not interfere with direct information exchanges between companies and the Government.

Island: A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Kilovar (kVAr): Unit of alternating current reactive power equal to 1,000 VArs.

Kilovolt (kV): Unit of electrical potential equal to 1,000 Volts.

Kilovolt-Amperes (kVA): A unit of apparent power, equal to 1,000 volt-amperes; the mathematical product of the volts and amperes in an electrical circuit.

Kilowatthour (kWh): A measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000 watts) of power expended for 1 hour. One kWh is equivalent to 3,412 Btu.

Line Trip: Refers to the automatic opening of the conducting path provided by a transmission line by the circuit breakers. These openings or "trips" are to protect the transmission line during faulted conditions.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers. See "Demand."

Load Shedding: Intentional action by a utility that results in the reduction of more than 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of service of the reporting entity's bulk electric power supply system. The routine use of load control equipment that reduces firm customer load is not considered to be a reportable action.

Lockout: A state of a transmission line following breaker operations where the condition detected by the protective relaying was not eliminated by temporarily opening and reclosing the line, possibly several times. In this state, the circuit breakers cannot generally be reclosed without resetting a lockout device.

Market Participant: An entity participating in the energy marketplace by buying/selling transmission rights, energy, or ancillary services into, out of, or through an ISO-controlled grid.

Megawatthour (MWh): One million watthours.

Metered Value: A measured electrical quantity that may be observed through telemetering, supervisory control and data acquisition (SCADA), or other means.

Metering: The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

NERC Interregional Security Network (ISN): A communications network used to exchange electric system operating parameters in near real time among those responsible for reliable operations of the electric system. The ISN provides timely and accurate data and information exchange among reliability coordinators and other system operators. The ISN, which operates over the frame relay NERCnet system, is a private Intranet that is capable of handling additional applications between participants.

Normal (Precontingency) Operating Procedures: Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Normal Voltage Limits: The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of regional reliability councils and encompasses essentially all the power regions of the contiguous United States, Canada, and Mexico.

OASIS: Open Access Same Time Information Service (OASIS), developed by the Electric Power Research Institute, is designed to facilitate open access by providing users with access to information on transmission services and availability, plus facilities for transactions.

Operating Criteria: The fundamental principles of reliable interconnected systems operation, adopted by NERC.

Operating Guides: Operating practices that a Control Area or systems functioning as part of a Control Area may wish to consider. The application of Guides is optional and may vary among Control Areas to accommodate local conditions and individual system requirements.

Operating Policies: The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions, which apply to all Control Areas.

Operating Procedures: A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Operating Requirements: Obligations of a Control Area and systems functioning as part of a Control Area.

Operating Security Limit: The value of a system operating parameter (e.g. total power transfer across an interface) that satisfies the most limiting of prescribed pre- and post-contingency operating criteria as determined by equipment loading capability and acceptable stability and voltage conditions. It is the operating limit to be observed so that the transmission system will remain reliable even if the worst contingency occurs.

Operating Standards: The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. An Operating Standard may specify monitoring and surveys for compliance.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Planning Guides: Good planning practices and considerations that Regions, subregions, power pools, or individual systems should follow. The application of Planning Guides may vary to match local conditions and individual system requirements.

Planning Policies: The framework for the reliability of interconnected bulk electric supply in terms of responsibilities for the development of and conformance to NERC Planning Principles and Guides and Regional planning criteria or guides, and NERC and Regional issues resolution processes. NERC Planning Procedures, Principles, and Guides emanate from the Planning Policies.

Planning Principles: The fundamental characteristics of reliable interconnected bulk electric systems and the tenets for planning them.

Planning Procedures: An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Post-contingency Operating Procedures: Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Protective Relay: A device designed to detect abnormal system conditions, such as electrical shorts on the electric system or within generating plants, and initiate the operation of circuit breakers or other control equipment.

Power/Phase Angle: The angular relationship between an AC (sinusoidal) voltage across a circuit element and the AC (sinusoidal) current through it. The real power that can flow is related to this angle.

Power: See “Real Power.”

Power Flow: See “Current.”

Rate: The authorized charges per unite or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Rating: A manufacturer’s guaranteed performance of a machine, transmission line, or other electrical apparatus, based on design features and test data. The rating will specify such limits as load, voltage, temperature, and frequency. The rating is generally printed on a nameplate attached to equipment and is commonly referred to as the nameplate rating or nameplate capacity.

Reactive Power: The electrical power that oscillates between the magnetic field of an inductor and the electrical field of a capacitor. Reactive power is never converted to nonelectrical power. It is calculated as the square root of the difference between the square of the kilovolt-amperes and the square of the kilowatts and is expressed as reactive volt-amperes.

Readiness: The extent to which an organizational entity is prepared to meet the functional requirements set by NERC or its regional council for entities of that type or class.

Real Power: Also known as "active power." The rate at which work is performed or that energy is transferred, usually expressed in kilowatts (kW) or megawatts (MW). The terms "active power" or "real power" are often used in place of the term power alone to differentiate it from reactive power.

Real-Time Operations: The instantaneous operations of a power system as opposed to those operations that are simulated.

Regional Reliability Council: One of ten Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Operator (RTO): An organization that is independent from all generation and power marketing interests and has exclusive responsibility for electric transmission grid operations, short-term electric reliability, and transmission services within a multi-State region. To achieve those objectives, the RTO manages transmission facilities owned by different companies and encompassing one, large, contiguous geographic area.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Regulations: Rules issued by regulatory authorities to implement laws passed by legislative bodies.

Relay: A device that controls the opening and subsequent reclosing of circuit breakers. Relays take measurements from local current and voltage transformers, and from communication channels connected to the remote end of the lines. A relay output trip signal is sent to circuit breakers when needed.

Relay Setting: The parameters that determine when a protective relay will initiate operation of circuit breakers or other control equipment.

Reliability Coordinator: An individual or organization responsible for the safe and reliable operation of the interconnected transmission system for their defined area, in accordance with NERC reliability standards, regional criteria, and subregional criteria and practices. This entity facilitates the sharing of data and information about the status of the Control Areas for which it is responsible, establishes a security policy for these Control Areas and their interconnections, and coordinates emergency operating procedures that rely on common operating terminology, criteria, and standards.

Resistance: The characteristic of materials to restrict the flow of current in an electric circuit. Resistance is inherent in any electric wire, including those used for the transmission of electric power. Resistance in the wire is responsible for heating the wire as current flows through it and the subsequent power loss due to that heating.

Restoration: The process of returning generators and transmission system elements and restoring load following an outage on the electric system.

Right-of-Way (ROW) Maintenance: Activities by utilities to maintain electrical clearances along transmission or distribution lines.

Safe Limits: System limits on quantities such as voltage or power flows such that if the system is operated within these limits it is secure and reliable.

SCADA: Supervisory Control and Data Acquisition system; a system of remote control and telemetry used to monitor and control the electric system.

Schedule: A statement of the pricing format of electricity and the terms and conditions governing its applications.

Scheduling Coordinators: Entities certified by the Federal Energy Regulatory Commission (FERC) that act on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule the distribution of electricity.

Seams: The boundaries between adjacent electricity-related organizations. Differences in regulatory requirements or operating practices may create "seams problems."

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

Security Coordinator: An individual or organization that provides the security assessment and emergency operations coordination for a group of Control Areas.

Short Circuit: An electric current taking a shorter or different path than intended.

Shunt Capacitor Bank: Shunt capacitors are capacitors connected from the power system to an electrical ground. They are used to supply kilovars (reactive power) to the system at the point where they are connected. A shunt capacitor bank is a group of shunt capacitors.

Single Contingency: The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Special Protection System: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components.

Stability: The property of a system or element by virture of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Stability Limit: The maximum power flow possible through a particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

State Estimator: Computer software that takes redundant measurements of quantities related to system state as input and provides an estimate of the system state (bus voltage phasors). It is used to confirm that the monitored electric power system is operating in a secure state by simulating the system both at the present time and one step ahead, for a particular network topology and loading condition. With the use of a state estimator and its associated contingency analysis software, system operators can review each critical contingency to determine whether each possible future state is within reliability limits.

Station (Electric): A plant containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy.

Storage: Energy transferred form one entity to another entity that has the ability to conserve the energy (i.e., stored as water in a reservoir, coal in a pile, etc.) with the intent that the energy will be returned at a time when such energy is more useable to the original supplying entity.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Subtransmission: A set of transmission lines of voltages between transmission voltages and distribution voltages. Generally, lines in the voltage range of 69 kV to 138 kV. Note: In this report, subtransmission focuses on lines at voltage levels between 69 kV and 115 kV.

Supervisory Control and Data Acquisition (SCADA): See SCADA.

Surge: A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.

Surge Impedance Loading: The maximum amount of real power that can flow down a lossless transmission line such that the line does not require any VArs to support the flow.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

Synchronize: The process of connecting two previously separated alternating current apparatuses after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management or operating supervision.

System Operator: An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

System Reliability: A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.

Thermal Limit: The maximum amount of power a transmission line can carry without suffering heat-related deterioration of line equipment, particularly conductors.

Tie-line: A transmission line connecting two or more power systems.

Time Error: An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction: An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Transactions: Sales of bulk power via the transmission grid.

Transfer Limit: The maximum amount of power that can be transferred in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions.

Transformer: An electrical device for changing the voltage of alternating current.

Transient Stability: The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance and to regain a state of equilibrium following that disturbance.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Loading Relief (TLR): A procedure used to manage congestion on the electric transmission system.

Transmission Margin: The difference between the maximum power flow a transmission line can handle and the amount that is currently flowing on the line.

Transmission Operator: NERC-certified party responsible for monitoring and assessing local reliability conditions, who operates the transmission facilities, and who executes switching orders in support of the Reliability Authority.

Transmission Overload: A state where a transmission line has exceeded either a normal or emergency rating of the electric conductor.

Transmission Owner (TO) or Transmission Provider: Any utility that owns, operates, or controls facilities used for the transmission of electric energy.

Trip: The opening of a circuit breaker or breakers on an electric system, normally to electrically isolate a particular element of the system to prevent it from being damaged by fault current or other potentially damaging conditions. See “Line Trip” for example.

Voltage: The difference in electrical potential between any two conductors or between a conductor and ground. It is a measure of the electric energy per electron that electrons can acquire and/or give up as they move between the two conductors.

Voltage Collapse (decay): An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control: The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Limits: A hard limit above or below which is an undesirable operating condition. Normal limits are between 95 and 105 percent of the nominal voltage at the bus under discussion.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage Stability: The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Watthour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.