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Planning Report

Changing Measurement and Standards Needs in a Deregulated Electric Utility Industry

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Research Triangle Institute

for

National Institute of Standards & Technology

Program Office
Strategic Planning and Economic Analysis Group

May 2000

U.S Department of Commerce
Technology Administration

Changing Measurement and Standards Needs in a Deregulated Electric Utility Industry

May 2000

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Executive Summary

The primary objective of this study is two-fold:

- ➤ to identify areas in which measurement and standards will be needed to capture the full benefits of wholesale and retail deregulation of the electric power industry in the U.S., and
- ➤ to identify, on a preliminary basis, the economic impacts of not meeting those needs.

Preliminary findings were presented at NIST's workshop on "Challenges for Measurement and Standards in a Deregulated Electric Power Industry" held December 6-8, 1999.

Measurement and standards can provide infrastructure enhancements that will help facilitate deregulation, secure its benefits, and avoid its potential pitfalls. The need for measurement and standards in this new environment is primarily related to

- ➤ the increased growth in the number and complexity of transactions,
- ➤ the increased number of market players and their information needs, and
- ➤ a shift from reliance on voluntary agreements among formerly integrated utilities to explicit contracts among many providers of different services.

We estimate that the economic impact of prospective opportunities that may be lost by not meeting these needs ranges from $3.1 to $6.5 billion. These estimates are more illustrative than precise because the U.S. is in an early phase of electric industry deregulation, and they are based on a limited number of survey responses from a sample of electric industry experts.

E.1 THE ROLE OF MEASUREMENT AND STANDARDS

Measurement and standards are technical tools that include scientific and engineering data, measurement and test methods, and industrial practices and techniques. They are called "infratechnologies" because they support core technologies by

- ➤ improving the efficiency of R&D;
- ➤ improving production processes and product and service characteristics; and
- ➤ reducing market transactions costs and providing the marketplace with reliable information on quality and other attributes of a product, service, or process.

Measurement and standards are essential in the electric power industry in expanding electricity use, reducing costs, maintaining or improving system reliability, and generally enhancing the technical and economic performance of the industry. Key areas in which their value is increasing are

- ➤ competitive metering of energy generation—including distributed generation—and ancillary services at the supplier and customer levels;
- ➤ monitoring bulk power flows and transactions;
- ➤ monitoring transmission and distribution system conditions;
- ➤ communicating and controlling generation, transmission, and distribution systems;
- ➤ monitoring power quality along these systems and in customer facilities; and
- ➤ assessing system conditions and contract compliance through the use of advanced diagnostic tools.

E.2 DEREGULATION TRENDS AND CHANGING CHARACTERISTICS OF THE ELECTRIC POWER INDUSTRY

Deregulation of wholesale electric markets has been moving forward since the issuance of FERC Orders 888 and 889 in 1996 and now with the recently released FERC Order 2000. Deregulation of retail electric markets has been moving more slowly: approximately one-half of the states in the U.S. have now begun to implement, or have decided to implement, retail competition.

Deregulation in both markets is leading to several key changes in industry structure and operation:

- Generation, transmission, and distribution are becoming functionally unbundled.
- The generation segment of the investor-owned utility (IOU) portion of the industry is becoming competitive, whereas transmission and distribution regulation of IOUs continues (by FERC in the first instance, and state utility commissions in the second).
- Transmission is now designated as a common carrier, and transmission system operators are required to provide open access, nondiscriminatory service to market players.
- Ownership and control of transmission is becoming separated in cases where groups of utilities are adopting the nonprofit independent system operator (ISO) model, whereas the two are remaining together in cases where groups of utilities are adopting the for-profit transmission company (TRANSCO) model.
- Many types of services—generation supply and services, AS to supplement basic transmission service, and customer services such as energy conservation and management, metering, and billing—are becoming "unbundled" with the result that they are being separately priced and open to competitive supply.

Advances in core and enabling technologies have taken place that are coincident with these changes and, in many cases, have served to drive or facilitate them. An example of a core technology advance is improvements in the cost and technical (heat rate) performance of gas turbines and combined-cycle units.

An example of an enabling technology advance is electronic data interchange (EDI) technologies and standards that provide a potential building block to support retail competition, although consistency between regional EDI systems is an ongoing concern.

However, for some technologies additional research is needed. An example is dynamic state monitoring systems that have the potential to increase transmission system capacity and support power system reliability, but these systems are still in development.

Some of these technology advances will enable the creation and spread of new products and services. For example, more accurate and widespread metering will allow loads to be more price-responsive, enabling services that seek to manage or otherwise affect customer usage patterns. From the suppliers' perspective, this tool is valuable to manage generation and transmission growth. Whereas a limited number of voluntary curtailment programs currently exist, it is estimated that up to a 2 percent reduction in peak demand could be obtained through widespread use of load control programs.

E.3 MEASUREMENT AND STANDARDS NEEDS TO SUPPORT DEREGULATION

Measurements and standards in the new environment will be of greatest value in supporting system operations, with its traditional concerns of system reliability and security, and market operations, particularly the exchange of information among many market players with different equipment.

The following examples indicate where new and enhanced measurements and standards can contribute to system operations:

- standardization of information availability requirements to support competition; currently, some purchasers have a competitive advantage because of asymmetric information;
- expanded and more frequent measurement and communication of system conditions to system operators;
- measurement and communication of transmission system dynamic performance to system operators;
- more frequent measurement and communication of distributed generators' output (aggregated) to system operators;
- dynamic control of distributed generation to maintain system reliability and to access potential ancillary service benefits;
- measurement and communication to system operators of ancillary services provided by generators (utility and merchant plants) and customers (through onsite generation or load curtailment); and
- security requirements to maintain system integrity as the market opens up and the number of players increases.

Measurement and standards will also be needed to support market transactions by helping ensure interoperability among equipment and systems provided by different vendors, by providing reliable and precise information for contracts and dispute resolution, and by developing pricing systems that reflect proper incentives. The following examples indicate where new and enhanced measurements and standards can contribute to market operations:

- creation of a seamless electronic data interchange (EDI) between metering and communication software and equipment, so that retail market players can obtain the various data they need when they need it;
- tracking of generator supply and power marketer/broker curtailments to determine whether and when they supplied generation/load relief or ancillary services to the system as required by contracts;
- tracking/tagging of power flows to assign cost responsibility for congestion on overloaded lines and constrained interfaces;
- more precise measurement of standard billing parameters (e.g., energy, demand, power factor) to support contracts; and
- more precise measurement of power quality, especially harmonics, flicker, sags, and surges to support contracts.

E.4 ECONOMIC IMPACTS

We conducted a survey of a sample of industry experts to

- identify key issues;
- identify key impact areas; and
- provide qualitative guidance on, and help develop quantitative estimates of, the economic impacts of not having adequate measurement and standards in place in a fully deregulated environment.

Preliminary results were presented at the NIST workshop in December 1999. We used feedback from conference participants with additional information to refine the qualitative guidance and the quantitative results.

Qualitative guidance provided by survey respondents includes the following:

- Within the system operations area, outages are a major concern, and enhanced measurement and standards can have a major impact in this area.
- Within the market operations area, the cost of market transactions is a major concern, and enhanced measurements and standards can have a major impact in this area.

We developed quantitative results for each of several important impact areas. To develop these results, we conducted a "gap analysis" (i.e., we estimated the performance gap between the potential benefits under full deregulation and the constrained benefits, that is, benefits in the absence of adequate measurements and standards), relative to a base year cost metric. We used the survey responses to develop each performance gap as a percentage of its base year cost metric. Because of the variability in these estimates, and the fact they are prospective rather than retrospective, they are presented as ranges rather than as point estimates.

The aggregate annual economic impacts range from $3.1 to $6.5 billion. This is a prospective annual estimate of not having adequate measurement and standards in place to capture the full benefits of electric deregulation.

Within this estimate, the impact of measurement and standards on system reliability is the largest impact category, representing 35 percent of the upper-bound estimate. Power quality issues for end users, average generation costs, and ancillary service costs each account for approximately 20 percent of the upper-bound estimate.

In summary, these estimates should be considered illustrative "first cut" estimates of prospective economic impacts. They are based on a survey of a limited number of electric industry experts early in the industry deregulation process. Although the results are not highly precise, the pattern of results within the system and market operations areas are plausible and provide early guidance to measurement and standards initiatives and investments.

1 Introduction

Deregulation of the electric power industry offers the potential of improving the economic efficiency of the production and use of electricity. However, achieving these gains in economic efficiency will require developing an infrastructure that can address the unique informational needs of an industry that is less centrally coordinated than before and more subject to the discipline of markets. This infrastructure includes new and improved measurement technologies and standards for tracking economic transactions in electricity markets and monitoring the performance of the system for generating, transmitting, and distributing electric power.

The industry includes a list of market players that are growing with deregulation. An overview of the electric industry supply chain is presented in Appendix A.

This study examines the broad set of measurement and standards needs of a deregulated electric power industry to help inform NIST's decisions regarding its role in meeting these infrastructure requirements.

The National Institute of Standards and Technology's (NIST's) mission is, in part, to provide these types of measurement and standards technologies. Specifically, the Electricity Division of NIST's Electronic and Electrical Engineering Laboratory (EEEL) seeks to "…provide the world's most technically advanced and fundamentally sound basis for all electrical measurements in the United States by realizing the International System (SI) of electrical units; developing improved measurement methods and calibration services; and supporting the measurements and standards of infrastructure needed by the U.S. industry to develop new products, ensure quality, and compete economically in the world market" (NIST, 1999).

This study examines the broad set of measurement and standards needs of a deregulated electric power industry to help inform NIST's decisions regarding its role in meeting these infrastructure requirements. It also identifies the types of expected improvements in the economic efficiency in the production and use of electricity with a deregulated system facilitated by this infrastructure. The expedient provision of the required infrastructure is a prerequisite for obtaining the economic efficiency improvements in a timely manner. In the context of this study, deregulation refers to the ongoing process of restructuring (or reregulation) of the wholesale and retail electric power markets. In addition, where appropriate, this study investigates evolving issues and needs not directly related to deregulation, such as the ongoing trend of generation outpacing transmission capacity growth and introduction of commercially competitive distributed generation, where they impinge on the infrastructure requirements of the industry.

The study does not provide a prediction of the expected course of deregulation or the future structure of the electric power industry.

The study does not provide a prediction of the expected course of deregulation or the future structure of the electric power industry. This topic has received significant attention in professional literature and congressional and regulatory testimonies, and the specific course of deregulation is still highly uncertain. We find, however, that most of the measurement and standards needs to support deregulation are generally independent of the eventual industry structure. Key issues and concerns, such as commodity measurement, transmission constraints, real-time communications needs, and information sharing requirements, are common to a wide range of potential deregulation outcomes.

1.1 OVERVIEW OF DEREGULATION

Beginning in the latter part of the 19th century and continuing for about 100 years, the prevailing view of policymakers and the public was that the government should use its power to require or prescribe the economic behavior of industry, especially those industries characterized as the "natural monopolies" such as electric utilities. The traditional argument is that for such industries it does not make economic sense for there to be more than one supplier—running two sets of wires from generating facilities to end users is more costly than one set. The predominant form of industry organization for electricity was (and largely still is) characterized by vertical integration and franchise service areas. Single companies serving a specific geographic area delineated by government generated, transmitted, and distributed the power, largely in isolation from the rest of the industry. However, since monopoly supply is not generally regarded as likely to provide a socially optimal allocation of resources, regulation of rates and other economic variables was seen as a necessary feature of the system.

The unwinding of economic regulation in the U.S. began in earnest at the federal level in the 1970s.

The unwinding of economic regulation in the U.S. began in earnest at the federal level in the 1970s. For a number of reasons, the public policy view shifted against traditional regulatory approaches and in favor of deregulation for many important industries including transportation, communications, finance, and energy. The major drivers for deregulation of electric power included the following:

- existence of rate differentials across regions offering the promise of benefits from more efficient use of existing generation resources if the power can be transmitted across larger geographic areas than was typical in the era of industry regulation;
- promise of new, low-cost technologies for electricity production;
- complexity of providing a regulated industry with the incentives to make socially efficient investment choices;
- difficulty of providing a responsive regulatory process that can quickly adjust rates and conditions of service in response to changing technological and market conditions; and
- complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes that promote economic efficiency while at the same time addressing equity concerns of regulatory commissions.

The 1978 Public Utility Regulatory Policy Act (PURPA) required that utilities purchase power from independent suppliers, opening up production to a potentially large number of such suppliers. The Energy Policy Act of 1992 (EPAct) further opened the door to competition among electricity generators by giving the Federal Energy Regulatory Commission (FERC) the right to require any utility to transship or "wheel" power supplied by another generator over their lines to a third supplier. Pursuant to EPAct, FERC in 1996 implemented Orders 888 "Final Rule on Open Access Nondiscriminatory Transmission" and 889 "Open Access Same-

Time Information System (OASIS)" to increase access to transmission systems and to operating information on these systems. Various forms of independent system operators (ISOs), regional transmission organizations (RTOs), functional unbundling, and organizational structures are being considered (and implemented) to enhance compliance with these Orders. The North American Electric Reliability Council (NERC) is considering changes in its structure, powers, and standards to help ensure reliability of the bulk power electric system in the aftermath of these Orders.

Customer choice of generation suppliers is now permitted in California, Massachusetts, Pennsylvania, and Rhode Island.

A few states have extended deregulation to the retail level. Customer choice of generation suppliers is now permitted in California, Massachusetts, Pennsylvania, and Rhode Island. Over a dozen other states have committed to retail competition in the future, and most other states are studying the possibility. While the specific form of the electric power industry is still evolving and the timetable for allowing retail competition will vary from state to state, it is clear that the future will be characterized by greater opportunities for consumers to select a supplier and for suppliers to make the technological and marketing choices without governmental oversight. A review of the status of retail deregulation is included in Appendix B.

The potential benefits of a competitive market for electricity are large. However, securing these benefits will not be costless. Significant investments in information infrastructures will be necessary.

1.1.1 Potential Benefits of Deregulation

The primary promise of deregulation of electric power is that it will promote greater economic efficiency in electricity generation, transmission, distribution, and use than will occur under a regulated environment. The main sources of economic efficiency gains commonly cited by proponents of deregulation include the potential deregulation offers to

- lower (total) generation costs by facilitating the interregional shipment of power (i.e., from low to high cost regions);
- stimulate investment in new low-cost generation and transmission resources through the removal of barriers to entry in generation and transmission; and

- promote improved use of electricity by allowing rates that more closely track the "true" cost of service and by the development of more product differentiation, for example, establishing markets for different levels of power reliability.

The potential benefits associated with deregulation are large because the system is large and the economic inefficiencies are, arguably, significant. The electric power industry represents approximately 0.25 percent of the U.S.'s gross domestic product (GDP). In 1998, the U.S. electric power industry had retail sales of $217.4 billion. Thus, even small changes in economic efficiency can lead to large economic impacts.

As shown in Table 1-1, generation accounts for approximately 75.6 percent of the retail cost of supplying electricity. Some industry experts estimate that the average cost of generation could be reduced by 5 percent (approximately $5 billion annually) through the more efficient use of existing generation assets and the adoption of new low-cost generation assets.

Table 1-1. Cost Components of Supplying Electricity
Generation accounts for over 75 percent of the cost of supplying electricity.

Cost Component	Share of Cost
Generation	75.6%
Transmission	2.5%
Distribution	5.6%
Market Transactions[a]	16.3%

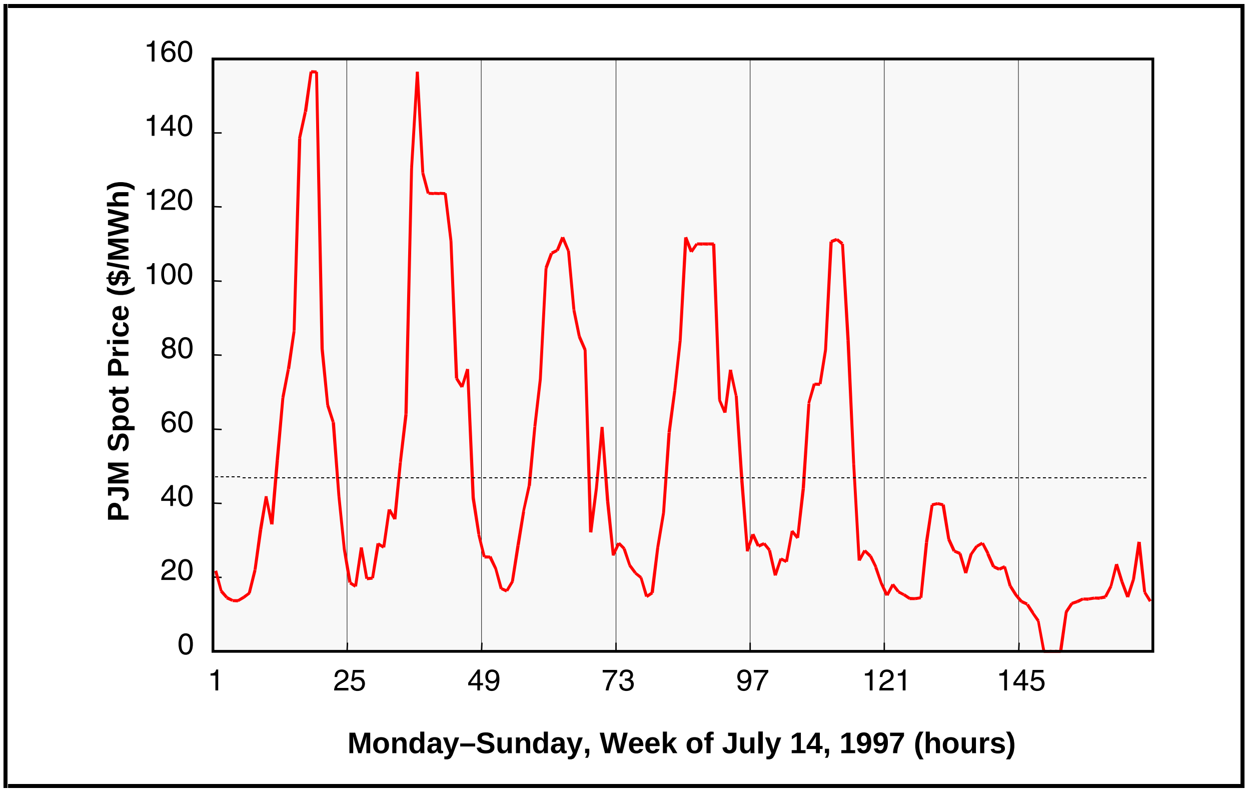
[a]Market transactions include customer accounts expenses, customer service and information expenses, sales expenses, and administration and general expenses.

Source: Energy Information Administration (EIA). 1997. *Financial Statistics of Major Investor Owned Utilities, 1996.* Washington, DC: U.S. Department of Energy.

Managing demand on the customer's side of the meter by leveraging demand price elasticity is also a potential source of benefits associated with deregulation. As shown in Figure 1-1, the spot price for electricity varies greatly depending on the day of the week and time of day.

Traditionally, system capacity has been designed to meet peak demand. And under asset-based compensation, regulated utilities have had little incentive to engage in activities to "clip" peak

Figure 1-1. Typical Fluctuations in the Spot Price of Electricity
The spot price of electricity varies greatly depending on the day of the week and time of day.



demand.[1] In addition, prices did not reflect the true cost of supplying energy during peak periods. Since customers did not see prices that reflected the high cost of consuming during times of peak demand they too had little incentive to "clip" peak demand. Deregulation and real-time pricing have the potential to motivate both suppliers and demanders to initiate programs (such as curtailable load programs) to lower peak demand.

1.1.2 Potential Costs Associated With Deregulation

As opponents of deregulation point out, the benefits of deregulation are not free. Potential costs associated with deregulation of electric power include the following:

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[1]Demand-side management (DSM) programs were initiated in the 1980s and 1990s. These programs were mandated by regulators and primarily focused on energy-efficient equipment. However, motivating electric utilities to pay their customers to purchase less of their product introduced its own inefficiencies.

- increased transaction costs to support market transactions,
- increased bulk transmission requirements,
- increased monitoring costs to support system reliability and power quality, and
- potential decreased in overall system reliability and power quality.

Transaction costs include contracting, metering, communication, and processing of information; billing; and dispute resolution. As shown in Table 1-1, these costs currently account for approximately 11 percent of the cost of supplying electricity. Most industry experts believe that the increased information needs associated with deregulation will increase total transactions costs.

Over the past 10 years, electricity sales have increased by 25 percent (in kWh) while bulk transmission capacity has increased by only 5 percent.

Most industry experts also believe that deregulation will lead to increased bulk transmission requirements. Over the past 10 years, electricity sales have increased by 25 percent (in kWh) while bulk transmission capacity has increased by only 5 percent. This trend is likely to continue as competitive generation markets and open access increase the average distance electricity is transported.

Expanding the transmission system will have both pecuniary and nonpecuniary costs. New transmission corridors cost approximately $500,000/mile 500kv line. A 1 percent increase in the capacity of the bulk transmission system would potentially cost $735 billion. In addition, public opposition to new transmission lines due to health concerns and the aesthetics of power lines has grown considerably over the decades.

System reliability and power quality are also concerns associated with deregulation. Reliable, high-quality electric power is one of the primary cornerstones of the U.S. economy. In fact, lack of reliability and power quality are frequently cited as the most important factors limiting growth in underdeveloped countries. Because of the U.S.'s dependence on (and expectations for) reliable power, unexpected outages can be costly. It is estimated that power outages currently lead to $29 billion (Hoffman, 1996) in annual losses for U.S. industries. In addition, sales of backup generation and power cleaning equipment exceeded $5.3 billion in 1998. Any degradation in reliability or power quality (real or perceived) could significantly increase these costs.

1.2 THE ROLE OF STANDARDS

Measurement and technology standards can play a role in helping to realize the potential benefits of a deregulated electric utility industry. This section presents the basic case for measurement standards and discusses their characteristics as infratechnologies.

1.2.1 The Justification for Measurement and Technology Standards in Industry

The basic rationale for measurement and technology standards in industries of any type are presented by Tassey (1997). He identifies four general areas where these standards can make a positive contribution to the economic performance of industries:

- *Quality/Reliability*. Standards are developed to specify an acceptable level of product or service performance along one or more dimensions such as functional levels, performance variation, service lifetime, efficiency, safety, and environmental impact. Thus, standards can help to avoid "sham" products or transactions, verify performance and delivery, and assure the credibility of offerings by new entrants to the industry.
- *Information*. Standards help provide evaluated scientific and engineering information in the form of publications, electronic databases, terminology, and test and measurement methods for describing, quantifying, and evaluating product attributes (e.g., verification of performance claims, thereby reducing disputes and market transactions costs and increasing market penetration).
- *Compatibility/Interoperability*. Standards specify properties that a product must have to work (physically or functionally) with complementary products within a product or service system. They provide a standard interface (i.e., interface standard) between components of a larger system, and they "open" systems technologies and allow multiple proprietary component designs to coexist. Optimization can still occur, but the cost of modifying physical and functional interfaces to allow components from different vendors to work together (i.e., to "interoperate") can be prohibitive. Full functionality is often not obtained by reengineering proprietary (nonstandard) interfaces. Integrated, "turnkey" systems offered by large companies may not be tailored for a user's particular needs, competitor's components may be superior, and there may be viable price competition for replacement of components. Standards can lead to effective integration of components and true compatibility of components in open systems.

➤ *Variety Reduction*. Standards limit a product to a certain range or number of characteristics, such as size or quality levels, primarily to attain economies of scale. Variety reduction goes beyond selecting certain physical dimensions of a product for standardization and now is commonly applied to nonphysical attributes, such as data formats, and to combined physical and nonfunctional attributes, such as computer architectures and peripheral interfaces. Standardization can either enhance or inhibit innovation. It can inhibit it when capital intensiveness grows as economies of scale are realized, which can exclude small, innovative firms from entry.

A standard can be specified in terms of design or performance levels. Design-based standards are more restrictive, so performance-based standards are generally more cost-effective. This distinction is especially important as the electric power industry goes through deregulation. Design-based standards that were effective in a regulated environment may be ineffective or overly restrictive in the new deregulated environment.

1.2.2 Measurement and Standards as Infratechnologies

Measurement and standards to support the deregulation of the electric power industry cover a broad range of technologies, procedures, and protocols.

Measurement and standards to support the deregulation of the electric power industry cover a broad range of technologies, procedures, and protocols. Measurement of commodities and system parameters is a prerequisite to establishing competitive markets and to ensuring reliable system operation when resources are separated from operating control. Measurement capabilities form the building blocks for standards, which in term support efficient R&D, production, and market activities.

Most of the measurement and standards can be viewed as infratechnologies.

Most of the measurement and standards can be viewed as infratechnologies. Infratechnologies are technical tools, including scientific and engineering data, measurement and test methods, and practices and techniques that are widely used in industry (Tassey, 1997). Infratechnologies play an important role in several stages of the economy.

➤ **Infratechnologies improve the efficiency of research and development (R&D).** Infratechnologies can stimulate R&D, improve the efficiency of R&D, and advance society's technological opportunities. Measurement technologies, test methods, technical standards, and standard practices allow researchers to conduct and discuss R&D using terminology and measurement methods and metrics that are understood by their colleagues and that allow for the replication and verification of research results.

- **Infratechnologies support the production process and can enhance product characteristics.** Infratechnologies can improve the efficiency of the production process and the characteristics of a product by providing tools for quality assurance and real-time process control.
- **Infratechnologies promote technology adoption and reduce market transactions costs.** Infratechnologies can increase the speed of market penetration by providing a language for communicating the characteristics and quality of a new product, process, or service.

NIST responds to market failures in the provision of infratechnologies by investing public funds in infratechnologies when private funding is inadequate to meet important strategic technical goals.

To varying degrees, infratechnologies have the characteristics of a public good. Such goods, unlike private goods, are characterized by consumption nonrivalry and by high costs of exclusion. Rationing of such goods is undesirable because the consumption of a public good does not impose costs on society since it does not reduce the amount of the good available to others. Further, the costs of excluding those who do not pay for the infratechnologies are likely to be high because they are typically embodied in products and processes (techniques), rather than in products that can be sold.[2] As a result of these characteristics, public goods are typically underprovided by private markets as compared to their socially optimal levels of provision (Stiglitz, 1988). The private sector might also underinvest in infratechnologies because its technology base is different from the core technology that industry draws on to develop its product or processes (Tassey, 1997).

NIST responds to market failures in the provision of infratechnologies by investing public funds in infratechnologies when private funding is inadequate to meet important strategic technical goals. The measurement technologies and standards NIST develops for the electric utility industry benefit the entire electric power supply chain as well as the consumers of electric power.

However, the scope of this study is not limited to NIST's potential roles for supporting deregulation. This study identifies the broad range of measurement and standard needs to support deregulation of the electric power industry, acknowledging that many private sector, trade organizations, and other government organizations

[2]In contrast, a regulated (or publicly owned) transmission system is not a true public good. Access to the system can be easily controlled and capacity limits and congestion effects mean that consumption of transmission resources imposes costs on other users.

will be involved in developing and implementing these measurement technologies and standards.

1.3 STUDY OVERVIEW

This study assesses the measurement and standards infrastructure needs of a deregulated electric power industry. It also provides estimates of the economic impact of the failure to provide this infrastructure. Such a failure implies that society will forego some of the potential benefits of a deregulated electric power industry because all of the potential gains in economic efficiency will not be realized. The intent of this study is not to assess all of the benefits and costs associated with deregulation. This study focuses only on the area where measurement and standards can potentially increase benefits or decrease costs.

Specific areas of interest include, but are not limited to, measurement and standards to support

- competitive metering for suppliers and consumers, energy, and ancillary services;
- bulk power transactions and monitoring;
- reliable transmission and distribution of electric power;
- communications and control technologies;
- advanced diagnostics;
- power quality; and
- distributed generation.

To identify and quantify the changing measurement and standards needs of the electric power industry, we conducted three stages of primary data collection with approximately 40 industry experts:

- ***Scoping interviews*** were used to investigate the evolving structure of the U.S. electric power industry and to identify potential areas where measurement and standards will play important roles.
- ***Detailed topic interviews*** were used to assess the importance of measurement and standards on specific areas identified during the scoping interviews. These areas included, but were not limited to, efficient provision of generation and ancillary services, systems operation, wholesale market transactions, and retail market transactions.

- ➤ ***Quantitative surveys*** were used to develop inputs to the economic impact analysis. Attendees at NIST's conference on measurement and standards needs to support a deregulated electric power industry were asked to provide their estimates of the impact of measurement and standards on several impact areas.

Appendix C contains the interview guide and survey questionnaire used to support the primary data collection activities. Table 1-2 contains a list of the survey respondents' company or organizational affiliation. The identity of individual contacts has been suppressed for confidentiality.

Table 1-2. Companies/Affiliations of Respondents
Telephone interviews with industry experts were the main source of primary data for the quantitative and qualitative analyses.

ABB Electric Metering	Northern States Power
California RTO	Paradigm Consulting
Carolina Power and Light	PJM Interconnection
Commonwealth Edison	Radian Research
Detroit Edison	Salt River Project
Duke Power Company	Southern Company
Electrotek	Square D/Schneider Electric
ENRON	Tampa Electric
Hypertek	University of Wisconsin, Electrical Engineering Department
National Regulatory Research Institute	Utility Translation Systems
North American Electric Reliability Council	Wisconsin Public Service
North Carolina Electric Membership Corporation	

Note: The number companies/affiliations listed in the table is less than 20 because, for some companies, more than one person was interviewed, and several respondents returned their surveys anonymously at the NIST conference on measurement and standards.

Findings from the scoping interviews and detailed topic interviews were used to support the discussion of measurement and standard needs in Section 4. The quantitative surveys were used to support the estimation of economic impacts described in Section 5. Appendix D contains an overview of the findings from the interviews and surveys.

In addition to primary data, we also used secondary data to support the analysis. Secondary data were collected from trade publications, professional journals, and statistical resources.

1.4 REPORT STRUCTURE

The remainder of the report is structured as follows. Section 2 contains a conceptual overview of the economic implications of deregulation and how the measurement and standards infrastructure influences economic efficiency. An overview of deregulation trends and implications is presented in Section 3. Section 4 presents a discussion of measurement needs and standards needs, respectively, to support deregulation. We present the economic impacts of failing to expeditiously provide the measurement and standards infrastructure in Section 5.

Appendix A describes existing activities and emerging participants in the electric power supply chain. Appendix B provides background on deregulation and notes some trends. The interview guide and survey questionnaire used to support the primary data collection activities and the development of quantitative results are presented in Appendix C. Appendix D summarizes the findings from the interviews. Appendix E describes the calculation of event cost metrics.

2 Conceptual Model of Deregulation and the Impact of Measurement and Standards

Economic efficiency refers to supplying end users' electric power needs at the lowest cost of production.

Industry restructuring is targeted at increasing the economic efficiency of the electric power system. In this context, economic efficiency refers to supplying end users' electric power needs at the lowest cost of production (including traditional generation, transmission, and distribution expenditures and market and system expenditures to support competition). This section presents a conceptual overview of the economic implications of deregulation and illustrates how measurement and standards influence economic efficiency and power reliability and quality.

2.1 ECONOMIC EFFICIENCY VIEWED AS AN OPTIMIZATION PROBLEM

The problem of efficiently generating and moving electricity from a set of producers to a set of consumers can be modeled as an optimization problem. Figure 2-1 shows the problem as a matrix with generators on the horizontal axis and consumers (electricity end users) on the vertical axis.[1]

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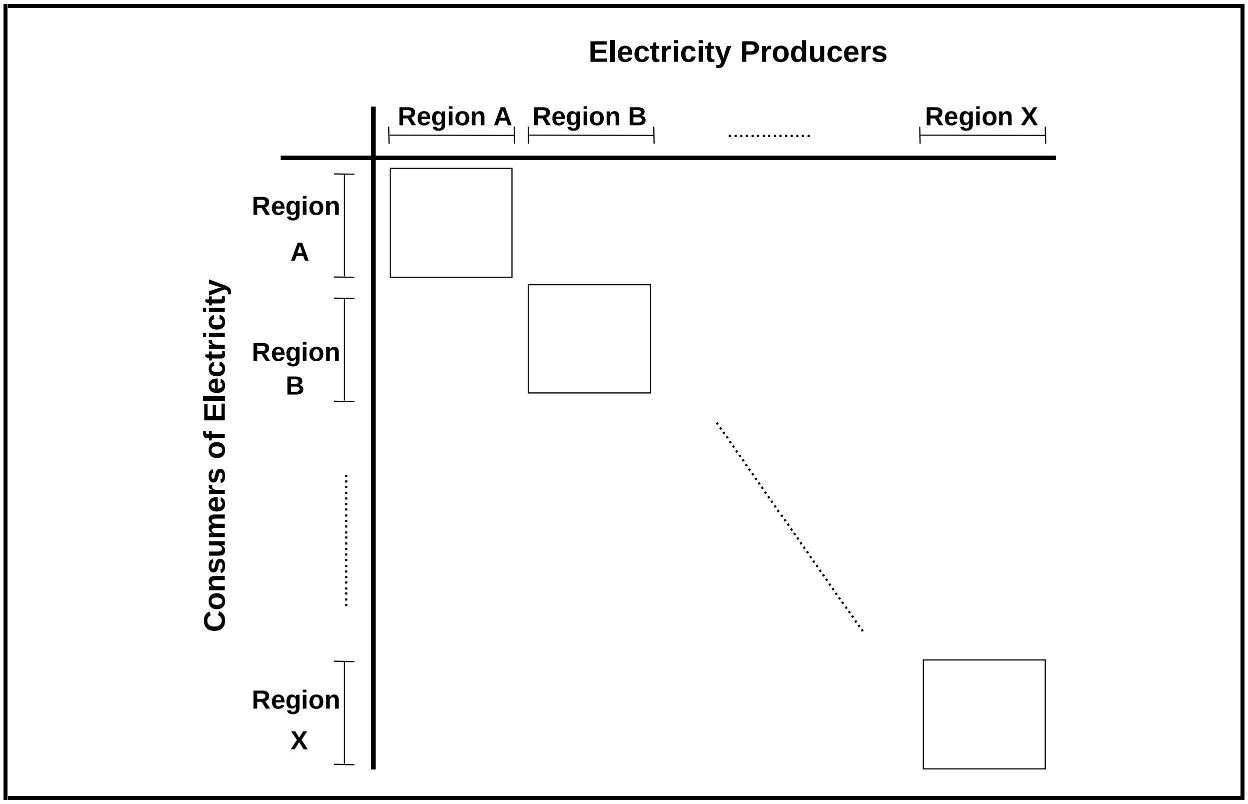
[1] One conceptual approach to determining the optional set of transactions is to use a linear programming (LP) model in which the equation in the LP system would relate producers to consumers and identify the cost of production and the cost causality of moving electricity from producers to consumers. The equations would also identify other system constraints, such as regulatory issues and physical limits on the transmission system.

Figure 2-1. Regulated Model
In a regulated scenario, regional monopolies select generation and transmission resources to optimize their individual, constrained regional model.

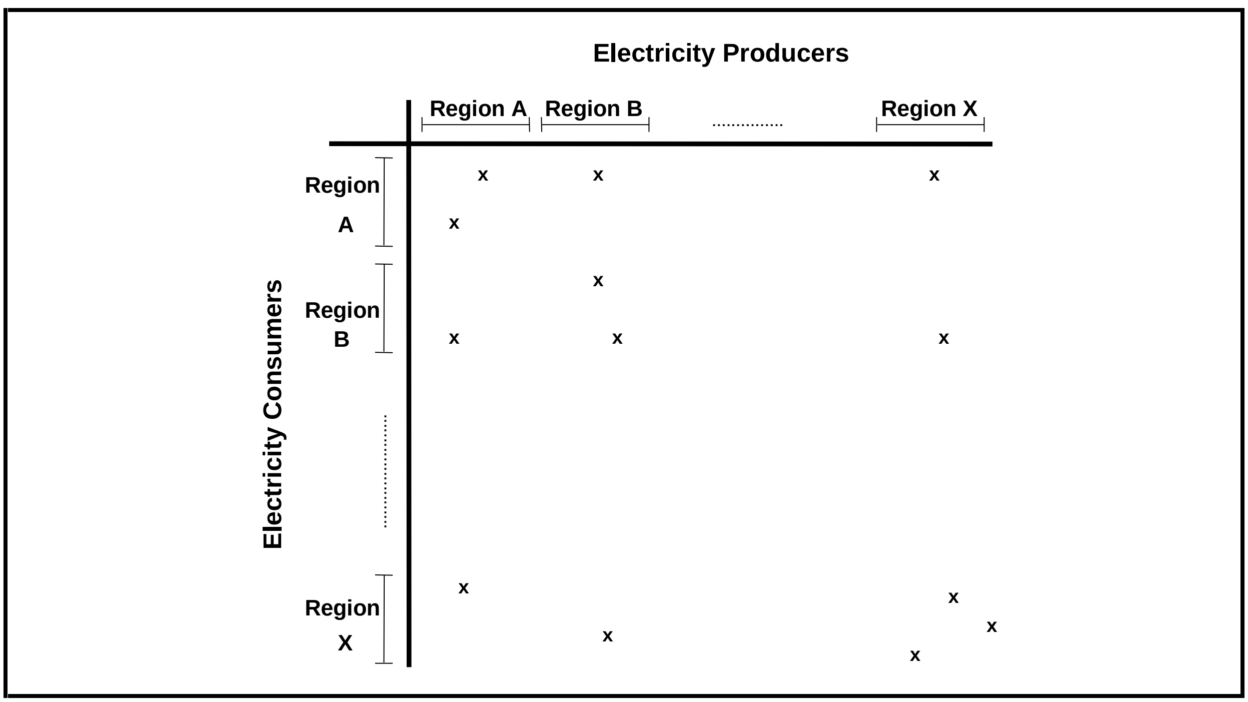


In an unconstrained competitive model, region boundaries would have no influence on the optimal transactions and grid structure, except for geographic constraints and the physical considerations of transmission costs and losses.

However, in the past, regulated regions have been viewed as natural monopolies, and each regulated region solved its own separate optimization problem. The boxes in Figure 2-1 reflect the boundaries of traditional regulated utilities that limit the possible number of power exchanges between producers and consumers. Thus, each region in effect selected its own generation, transmission, and distribution assets (including monitoring and communication assets to support system operations) to minimize the cost of supplying electricity to the consumers in its region. In the long run, a region's physical assets could be considered endogenous to the optimization problem. In this report, the conceptual model illustrated in Figure 2-1 is referred to as a regulated model.

Now, with deregulation, the objective is to restructure the electric power system to gain efficiencies from expanding transactions beyond a series of regional optimization models to a single (national or North American) optimization model. As shown in Figure 2-2, with deregulation consumers in Region A can receive power from producers outside of Region A (where the x's represent transactions). In effect, we have relaxed the model's constraints by allowing "off diagonal" transactions. In the long run, generation and transmission assets will be selected so that the optimal grid minimizes the cost of electricity for consumers.[2] This scenario is referred to as the competitive model.

Figure 2-2. Competitive Model
In an unconstrained competitive scenario, the optimal allocation of generation and transmission resources is different (compared to a regulated monopoly scenario) because transactions between regions are possible.



[2]An unregulated competitive scenario may also lead to competition between generators within a region. A regulated utility's region may have included several control areas that may have had little interconnection.

However, in the short run, generation and transmission assets are largely fixed, and the least-cost solution is obtained relative to these constraints. This conceptual model is referred to as the constrained national model. Conceptually, the constrained competitive model must be as least as efficient as the regulated (local monopoly) model.[3] In addition, the constrained competitive model will probably be less efficient than the (unconstrained) competitive model because of the short-run constraints on modifying generation and transmission assets.

2.2 TRADE-OFF BETWEEN COST AND QUALITY

Deregulation may lead to the supply of electric power at different reliability and power quality levels.

An important dimension missing in the simple optimization problem described above is that electric power need not be supplied as a homogeneous commodity. In general, electric power service can vary with respect to its overall quality that includes all the nonpecuniary characteristics of electricity of importance to the consumer. Foremost among these characteristics are power reliability and power quality.[4]

There is potentially a trade-off between the cost of power supply and its reliability and power quality. For example, in the extreme, redundant transmission systems could be built and high generation reserve margins maintained to support power reliability. Other examples are the choices system planners face regarding how much to invest in real-time communications to monitor transmission system, flexible alternating current transmission system (FACTS) to control power flow, fault trips to limit cascading outages, and capacitor banks to maintain power quality. Increased use of these devices can increase the level of quality; however, they are costly.

Figure 2-3 illustrates the tradeoff between the cost of delivered power and reliability: higher reliability costs more. All points on the curve represent the best-practices or efficient frontier. Thus, they are all efficient in the narrow sense that each point represents the minimum cost at which a given level of quality can currently be achieved. Any point above the frontier is inefficient, and points below it are unattainable with present technology and market structure.

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[3]Under the constrained national model, all consumers can still choose to purchase power from their regional producers as before.

[4]The combination of the two desirable attributes is often referred to as "clean" power.

Figure 2-3. Trade-off between the Electric Power Price and Power Reliability
The efficiency frontier represents the least-cost of producing a given level of power reliability.

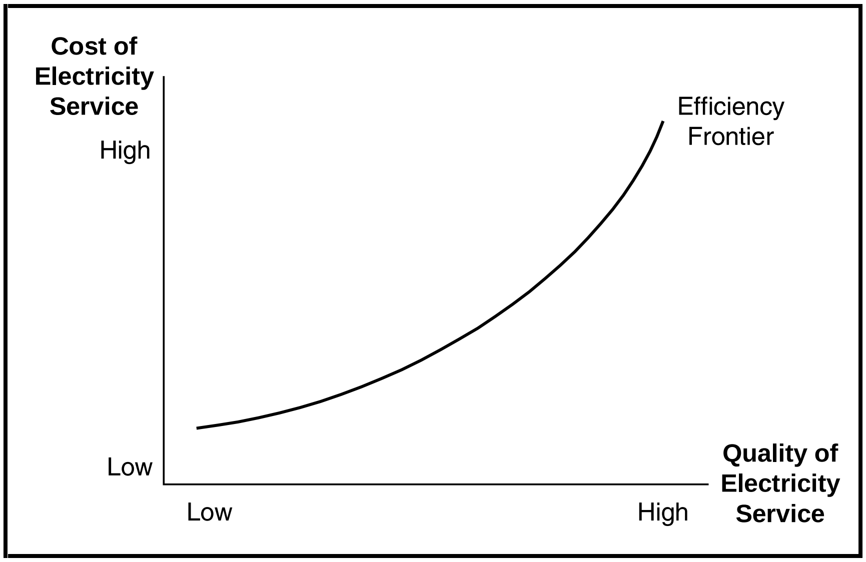


Figure 2-4 shows the indifference map for a single consumer. It represents the preferences of the consumer between power price and reliability. The consumer's economic well-being or "utility" is constant along each curve: higher numbered curves have higher levels of utility. The point, (A), where the consumer's utility curve and the efficiency frontier are tangent represents the cost/quality combination with the highest possible utility given the present technology and market structure embedded in the efficiency frontier.

It has been argued that utilities compensated under a rate-based rate of return structure may have the incentive to overinvest in capital assets (this has been referred to as gold plating or the Averch-Johnson effect). As a result, historically, utilities have had incentives to invest in capital assets to maintain reliability—potentially beyond the point that is economically efficient from a social planner's perspective. For example, they may be operating at point B in Figure 2-4. With deregulation suppliers are expected to conduct an explicit assessment of the trade-off between the cost and quality of electricity service.

This type of evaluation between the investments to enhance reliability or lower cost has already begun. For example, the California regional transmission organizations (RTO) proposes to

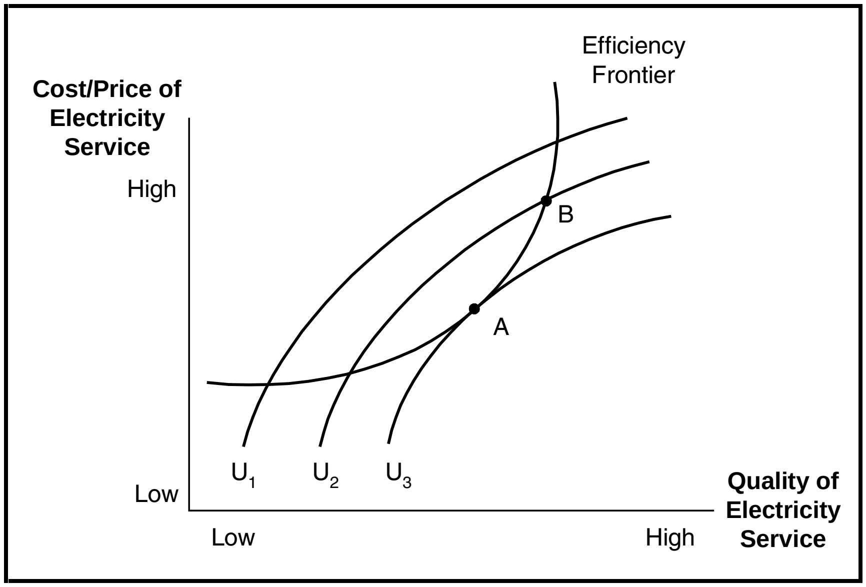


Figure 2-4. Consumer Indifference Map between Electric Power Price and Reliability
Each curve represents the focus of price-reliability values that provide a given level of consumer welfare or "utility." Higher numbered curves have higher utility levels.

evaluate what would increase the utility of their customers the most: investments targeted at lowering the cost of electricity service or investments that are targeted at improving reliability and power quality (CASO, White Paper #2).

As mentioned earlier, the efficiency frontier is a function of the present state of technology and market structure. One of the objectives of deregulation (i.e., a change in market structure) is to shift the efficiency frontier to the lower right, thereby increasing the possible utility of electricity consumers. As shown in Figure 2-5, shifting the efficiency frontier to the lower right allows the provision of a given level of quality at a lower cost (A_1). Alternatively, quality could be increased at the same cost (A_2), or a combination of low cost and increased quality could be obtained (A_3). The shape of the consumer's utility curves would determine which cost/quality selection would maximize consumer's utility.

Restated, without adequate measurement and standards, the full shift in the efficiency frontier envisioned for deregulation may not be realized.

Measurement and standards have the potential to contribute to the outward shift of the efficiency frontier. Restated, without adequate measurement and standards, the full shift in the efficiency frontier envisioned for deregulation may not be realized. Figure 2-6 illustrates the potential impact of measurements and standards. For example, without adequate measurement and standards, additional costs may be needed to maintain the reliability and power quality

Figure 2-5. Shift in the Efficiency Frontier due to Deregulation

One of the objectives of deregulation is to shift the efficiency frontier, lowering cost and/or increasing the quality of electricity service.

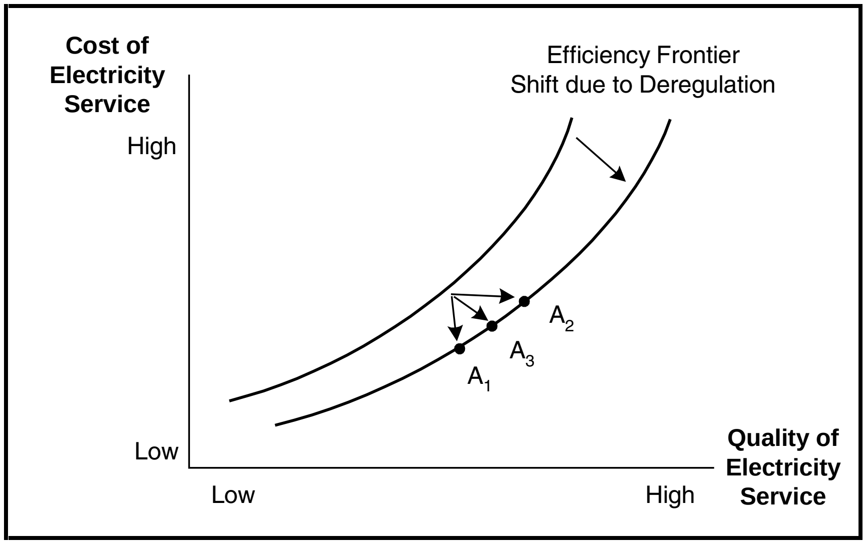
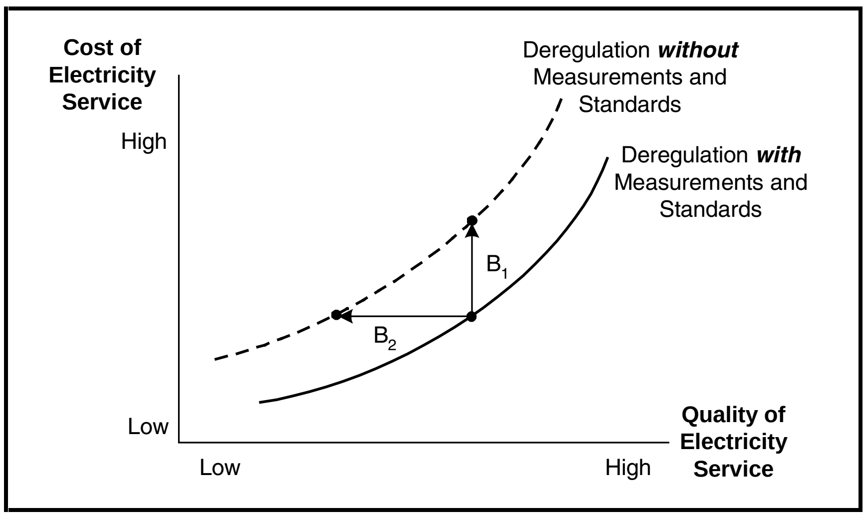


Figure 2-6. The Role of Measurement and Standards

Without measurement and standards, the full benefits of deregulation may not be achieved.



of the system (B_1). Or, without adequate measurement and standards, the quality of electricity service may decrease given available resources/costs (B_2). Changes in system costs and electricity service quality associated with inadequate measurement and standards are the focus of the quantitative analysis presented in Section 5.

2.3 ECONOMIC EFFICIENCY AND PRODUCT DIFFERENTIATION

Measurement and standards are needed to support the infrastructure necessary for product differentiation in the electric power market.

An additional role of measurement and standards may be to facilitate the differentiation of electric power by providing the infrastructure necessary for product differentiation.[5] In this context, product differentiation refers to the ability of electricity service providers to supply electricity with different levels of reliability or power quality to different groups of customers.

Figure 2-7 conceptually illustrates the potential benefits associated with product differentiation. Figure 2-7 shows two consumers: Consumer A has a relatively low value for power electricity service quality and Consumer B prefers a high level of quality. Under a traditionally regulated industry, electricity service is supplied at only one level of quality (within a service region) because the utility does not have the incentive to differentiate its product. This reliability level shown is “average” or Q_1. Consumer A’s well-being is U_1^A, B’s is U_1^B. Under deregulation, different (or the same) suppliers may offer two levels of reliability, Q_2^A and Q_2^B, with the result that each consumer is on a higher indifference curve. Social welfare (the sum of the two utility levels) has risen.

2.4 TECHNICAL AND MARKET INFORMATION NEEDS TO SUPPORT A DEREGULATED INDUSTRY

As part of this project, we investigated the technical and market information needs to support a deregulated electric power industry. This distinction between technical and market information is important because the characteristics of the information needs and the impact on economic efficiency and clean power (of not meeting these needs) are generally different.

[5]Measurement and standards also have the potential to increase the economic efficiency of the unconstrained competitive model. However, the focus of this report is on the impact of measurement and standards on a restructured industry and implies a relatively short time horizon (10 to 20 years) where most of the generation and transmission assets are inherited from the previous regulated monopoly model.

Figure 2-7. Product Offerings under Regulation and Deregulation
With deregulation electric power suppliers may find it profitable to differentiate their product. This would raise consumer welfare.

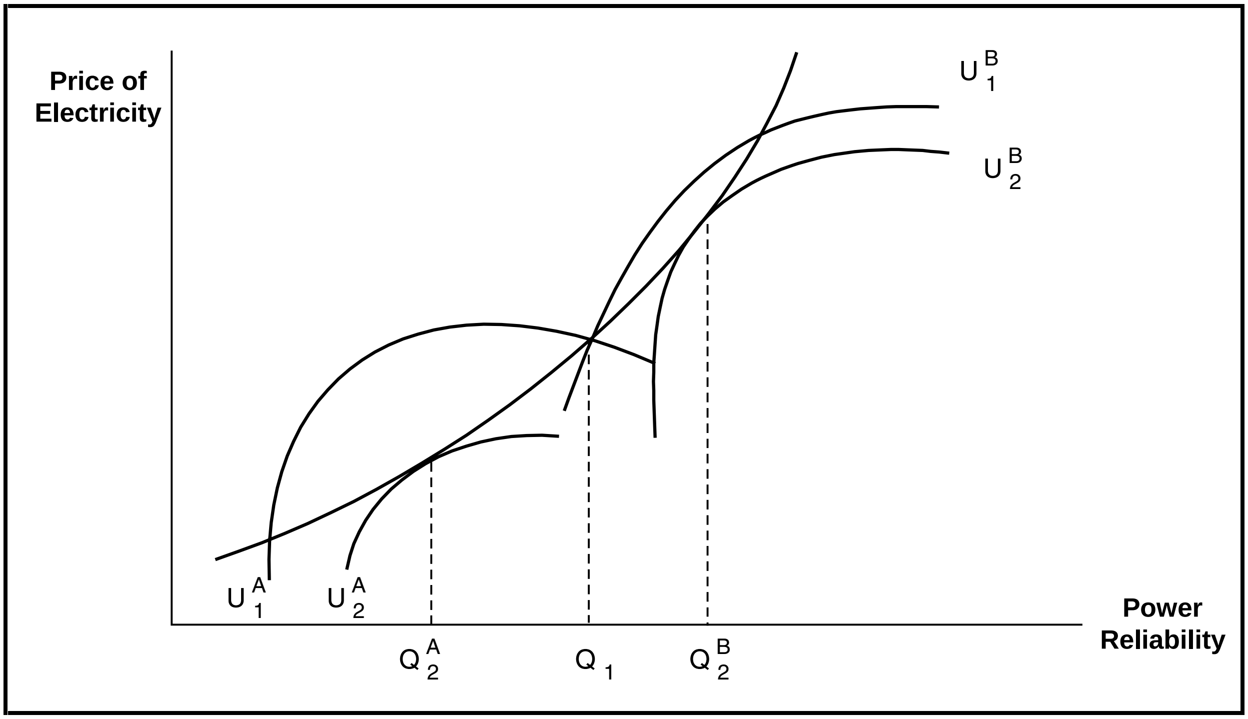
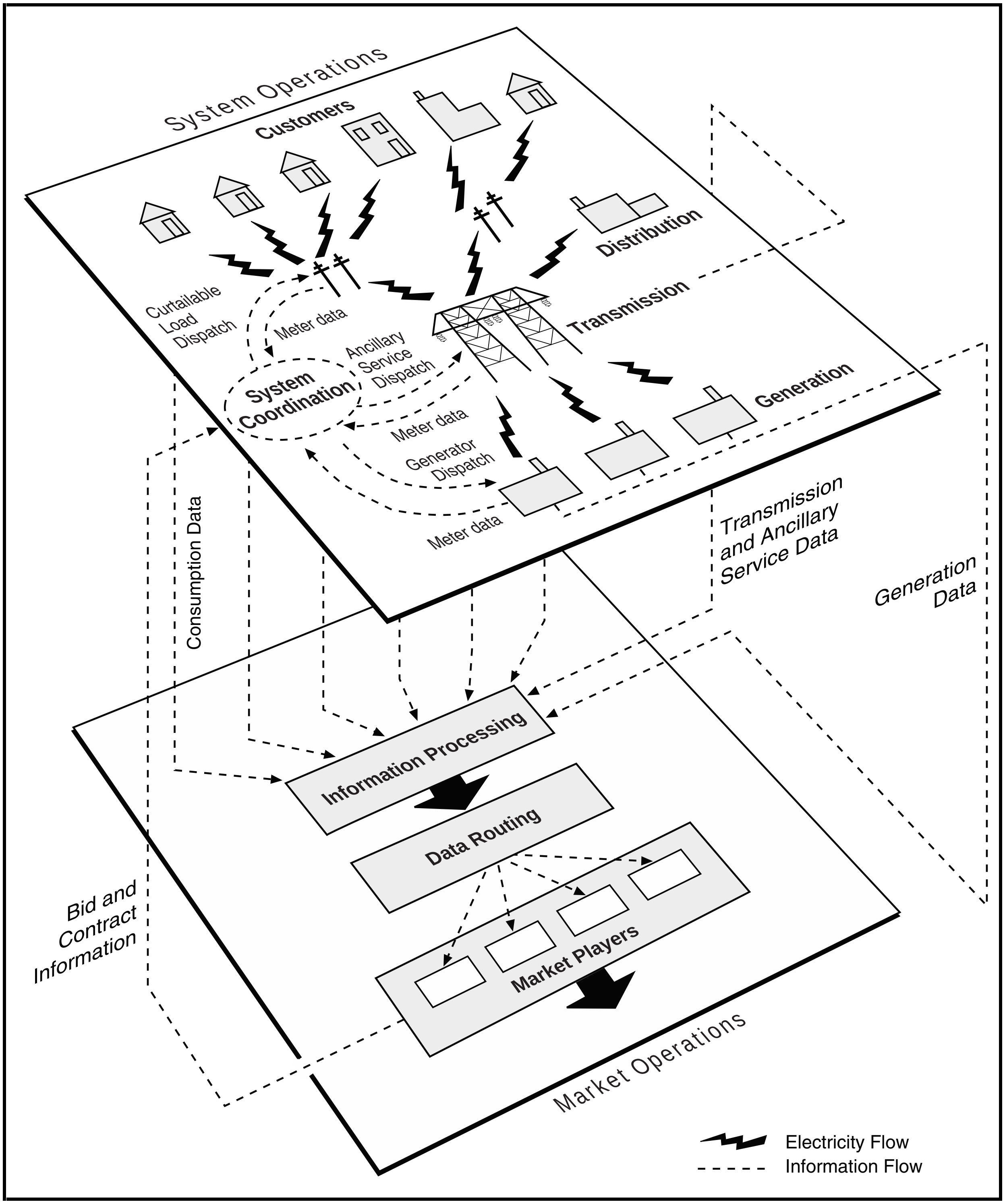


Figure 2-8 illustrates the distinction between these two categories of information using two separate parallel planes of operation: systems operations and market operations. Information flows have historically been concentrated within each plane with minimal interchange of technical information and market information. However, with deregulation significantly more information will need to be exchanged between the two planes. Increasingly market forces will drive system operations, and more technical information will be needed to support market operations.

As an example of how information may flow between the two planes in Figure 2-8, consider the following:

➤ In the initial step, data on generating and transmission system resources (e.g., their availability, capability, operating levels, and incremental operating costs) and on forecasts of load and energy from the top plane may be shared with selected market players in the lower plane. In the process, information from different sources and regions will need to be aggregated, processed, and routed to selected market players.

Figure 2-8. Information Needs for System and Market Operations
Traditionally there has been limited interaction between system and market operations. However, with deregulation the information flows between the two planes will increase substantially.



- These market players will bid generation resources, curtailable load resources, and ancillary services into the market. These data flow from the market players in the lower plane to the system coordinator in the top plane (or to a separate power exchange, as in California).
- The system coordinator (or power exchange) in the top plane will select the preferred resources and services. The system coordinator will then schedule (sometimes with the aid of scheduling subcontractors) and dispatch generation and curtailable load resources to meet (or reduce) demand and dispatch ancillary services to augment basic transmission service.
- Data on generation and curtailable load dispatched, ancillary services used, and customer load and energy use will flow from the top plane to market players in the lower plane, where it will be incorporated into bills they render to other market players. These other market players will include the system coordinator and local distribution companies and may include bilateral contract wholesale market customers and bilateral contract retail market customers.

Telephone interviews were used to investigate the technical information needed to support deregulation. Technical information primarily supports the physical operation of the electric power system. It supports both economic efficiency and clean power. The distinguishing characteristics of technical information are the importance of real-time data transfer and communication reliability. To maintain reliability, system coordinators need to be able to monitor inflows and outflows from the grid, as well as conditions throughout the system. Operating conditions must be measured, transmitted, and processed and then responses dispatched all in real time to maintain system stability. In the future, real-time state information on system operations may be used to support market functions such as estimating cost causality of bulk transaction on the transmission system. Some of the technical information flows to support system operations identified during the telephone interviews are the following:

- monitoring and control of generation and ancillary services (standards and communications protocols are needed),
- real-time monitoring and control of transmission system (capacity utilization measurements/standards and dynamic state analysis are needed), and
- real-time communications links to end users to support demand-side management activities (standards and communications protocols are needed).

Because of the large number of end-user meter reads, interoperability and processing costs are important issues for supporting deregulation.

We also used the telephone interviews to investigate market information needed to support deregulation. Market information primarily supports the pricing and billing of the electric power system and is used for forecasting and dispatch of generation and ancillary services. Key characteristics are that information is recorded at regular intervals (hourly) and communicated periodically (daily) to central processing centers. In addition, information reflecting the value/price for energy and ancillary services needs to be communicated back to suppliers hourly (at least) to get response. Because of the large number of end-user meter reads, interoperability and processing costs are important issues for supporting deregulation. In addition, usage data are proprietary (and valuable); thus, security will be an important issue. Some of the market information flows that we investigated are the following:

- measurement of generation and ancillary services supplied (cannot sell what cannot be measured);
- measurement of transmission costs (transmission causality models are needed);
- end-use consumption metering (standards needed to lower cost);
- communication, aggregation, and redistribution systems (common protocols and standards needed to lower costs); and
- special information needs to support the growth in the number of players and to lower market barriers to entry.

As part of our interviews, we developed a detailed characterization of the technical and market information flows required to support a deregulated electric power industry. We also qualitatively described the measurement and standards needs required to support the efficiency and reliability of each information flow.

3 Future Implications of Deregulation for the Electric Power Industry

This section provides an overview of the changing characteristics and needs of the electric power industry as a result of deregulation. We identify the emerging information, technology, and resource needs that will be necessary to effectively manage a deregulated power industry. From this backdrop of emerging needs, Section 4 and Section 5 discuss the roles measurement and standards may play in meeting these needs.

3.1 DEREGULATION TRENDS AND THE CHANGING CHARACTERISTICS OF THE ELECTRIC POWER INDUSTRY

Regardless of the eventual evolution of the industry structure, most of the physical characteristics and needs of the deregulated industry will be the same.

Restructuring of the electric power industry could result in any one of several possible market structures. In fact, different parts of the country will probably use different structures, as the present trend indicates. The eventual structure may be dominated by a power exchange, bilateral contracts, or a combination. A strong Regional Transmission Organization (RTO) or a minimal RTO may operate in the area, or a vertically integrated utility may continue to operate a control area.

However, regardless of the eventual evolution of the industry structure, most of the physical characteristics and needs of the deregulated industry will be the same. The metering, communications, and control requirements of a restructured electric power industry are primarily being driven by the fundamental change of increasing reliance on markets and contracts and decreasing reliance on regulation and vertical integration. These fundamental changes are common to almost all potential restructuring scenarios. Similarly, the need to extract more performance from the transmission system is related to the difficulty of constructing transmission, and increasing commercial pressure to use transmission, not necessarily to the specifics of how industry restructuring moves forward. As a result, the general need to advance metering and monitoring technology seems to be broadly based on national requirements that are not sensitive to the specific details of restructuring implementation.

In general, deregulation will lead to changes in several important industry characteristics:

- ➤ Commercial provision of generation-based services (e.g., energy, regulation, load following, voltage control, contingency reserves, backup supply) will replace regulated service provision. This drastically changes how the service provider is assessed.
- ➤ Individual transactions will replace aggregated supply meeting aggregated demand. It will be necessary to continuously assess each individual's performance.
- ➤ Services will be unbundled. It will be necessary to separately evaluate each type of transaction.
- ➤ Time frames will shorten. New services will be measured over seconds and minutes instead of hours.
- ➤ Transaction sizes will shrink. Instead of dealing only in hundreds and thousands of MW, it will be necessary to accommodate transactions of a few MW and less.
- ➤ Supply flexibility will greatly increase. Instead of services coming from a fixed fleet of generators, service provision will change dynamically among many potential suppliers as market conditions change.
- ➤ Greater and greater performance will be required from existing transmission resources. Transmission will be increasingly difficult to build, planning transmission enhancements will slow even further, but commercial pressure will demand that existing resources be used to the fullest.

All of these changes have important implications for data collection, communications, and control requirements. Fundamentally, they result in three basic needs:

- faster, more accurate, and cheaper metering to accommodate commercial transactions (revenue metering) that are smaller in MW size; require faster services (including dynamic response); and come from a much larger group of resources (generators and loads)
- real-time data acquisition, communications, and control capabilities to support market-based systems operations where price signals replace command-and-control operations
- real-time data acquisition, communications, and control capabilities to extract as much performance as possible from transmission and distribution facilities

If these needs cannot be met, deregulation of the electric power industry will be severely hampered.

3.1.1 Separation of Resources and System Operations

One of the most important implications of deregulation is that it will lead to separation of resources from system operations. With this separation emerges the need to evaluate the performance of the individual components of the power system.

> Deregulation will likely lead to a separation of resources from system operations. This shifts the emphasis away from system performance and toward individual unit or market participant performance.

State regulators have historically judged the overall performance of each vertically integrated monopoly utility. In the regulated framework, all components of the system worked together and were compensated based on the overall performance of the system. Regulators could reward or punish utilities by controlling the rates the utilities were allowed to charge. While the assessment certainly had (and has) quantitative parts and often focused on individual areas of performance (e.g., assessing if an investment was "used and useful"), the judgment was always on a fairly large scale and largely subjective. Thus, in the regulated framework, the emphasis is on the performance of the fleet of resources, and individual performance is only important in how it affects the aggregate objective.

With deregulation, the emphasis shifts to individual performance. Previously suppressed (internalized) pricing systems now must be formalized to support market transactions. In addition, formal contracts are now needed to specify what is expected and the payment associated with the individual providing the agreed-upon services, as well as payments associated with providing unanticipated services. Under deregulation, individual units will no longer be willing to sacrifice themselves for "the good of the system" without compensation.

One of the main benefits of vertically integrated organizations is that they reduce transaction costs by internalizing prices and centralizing control. Transaction costs to support market operations will be one of the greatest costs associated with deregulation. In general, there are three types of transaction costs: information costs, contracting costs, and enforcement costs. Any transaction requires knowledge about the opportunities for exchange, the nature of the items to be exchanged, and the willingness of the participants to engage in a bargaining process. This information is not costless and the lack of information can prevent certain exchanges from ever occurring (Bromey, 1991).

The challenge for a deregulated electric power system that has separated system control and resources will be to establish a pricing and enforcement system that signals the correct incentives to individual system components. This will be important both in the efficient operation of existing assets and in attracting investment in new generation and transmission resources.

3.2 ENABLING TECHNOLOGIES

Deregulation would not be possible without a broad range of enabling technologies to support the increased demand for monitoring, metering, communications, and control. Significant technology advances have been made within and outside the electric power industry. In addition, many technical areas were identified during our interviews where additional research is needed.

3.2.1 Enabling Technology Advances

Many of the technologies that make deregulation possible have been developed outside the electric power industry and represent spillover benefits. Examples of these technologies include the following:

Many of the technologies that make deregulation possible have been developed outside the electric power industry and represent spillover benefits.

- Advances in microprocessor performance and costs will support the monitoring, transfer, and processing of information.
- Electronic data interchange (EDI) technologies and standards provide a potential building block to support retail competition. However, consistency between regional EDI systems is an ongoing concern.
- Data management and storage system technologies are developed to support a wide range of commercial applications and are essential to implementing retail competition.
- Advances in wireless technologies will support the implementation of automated meter reading (ARM) systems.
- Expanded Internet access and high-speed data links will support communications needs for competitive generation and retail competition.

3.2.2 Infratechnologies Where Additional Research is Needed

During our interviews, industry experts indicated many areas where technology advances will be needed to support deregulation. Many of these areas include infratechnologies that are needed to support system and market functions. The identified needs range from instances where available technologies are inadequate to instances where technologies exist but are too costly for widespread implementation:

- Security technologies have not yet matured in the electric power industry. Security issues will be come increasingly important with the increase in the number and diversity of market participants at all levels of the supply chain.
- Dynamic state monitoring systems have the potential to increase transmission system capacity and support power system reliability.
- Improvements in cost causality models for bulk transmission are needed for efficient pricing of transmission services.
- Models and monitoring systems to determine thermal limits for transmission lines have the potential to increase transmission system capacity and support power reliability.
- Models are needed to predict voltage instabilities and voltage collapse. Existing real-time causality models are inadequate.

- Technologies to support equipment cost reductions are needed for widespread implementation of advanced metering.
- Advances to reduce the cost of flexible AC transmission (FACTS) are needed. FACTS will potentially be an integral tool supporting control and reliability of the bulk transmission system. However, additional research is needed to reduce the cost before widespread implementation is economically feasible.
- Technology enhancements for phase angle metering are needed to improve accuracy and lower cost.
- Transaction management systems are needed to reduce operator work load and reduce mistakes.
- Data synchronization techniques are required to eliminate problems caused by data collected from different parts of the system arriving at the control center at different times, resulting in an inconsistent view of the power systems.
- Instrumentation for early detection of cable failures is needed along with technology and real-time control capabilities to prevent cascading failures once cable failures are identified.

3.2.3 Infratechnologies that Will Enable New Products and Services

Research and development within the electric power industry is being driven by the need for technology advances to support the ongoing deregulation process. However, new technology advances and the implementation of information systems will enable new products and services not originally foreseen. As with the evolution of the Internet where “technology push” led to development of new applications, the technology advances and information infrastructures driven by deregulation of the electric power industry will lead to new, spin-off market opportunities:

- More accurate and widespread metering will allow loads to be price-responsive enabling services targeted at managing demand-side usage. From the suppliers’ perspective, this tool is valuable to manage generation and transmission growth. Whereas a limited number of voluntary curtailment programs currently exist, it is estimated that up to a 2 percent reduction in peak demand could be obtained through widespread use of load control programs.
- More accurate and widespread metering will also enable products and services targeted for end users to more

efficiently manage electricity consumption. Detailed end-use usage profiles will become available for smaller commercial and industrial and residential customers, along with the technology to control individual loads.

- ARM for electric and gas services may merge, accelerating the development of integrated energy service providers.
- Path-dependent models and tagging technology may help stimulate the market for green power.

3.3 KEY ISSUES RELATED TO RESTRUCTURING THE ELECTRIC POWER INDUSTRY

Viewed from one perspective, not much changes in the electric industry with restructuring. The same functions are being performed, essentially the same resources are being used, and in a broad sense the same reliability criteria are being met. In other ways, the very nature of restructuring, the harnessing of competitive forces to perform a previously regulated function, changes almost everything. Each provider and each function become separate competitive entities that must be judged on their own. Measurement and quantification become critical to buying and selling power.

Several technical issues will need to be addressed as deregulation progresses. Measurement and standards will play an important role in developing the infratechnologies needed to meet the challenges associated with restructuring. Areas where measurement and standards will be important include

- increased transmission demand,
- service quantification,
- reliability criteria,
- real-time electric pricing,
- unbundling of ancillary services,
- reduced generator and transaction sizes,
- power quality, and
- supplier choice.

These issues are discussed below.

3.3.1 Increased Transmission Demand

Deregulation will lead to increased pressure to extract more performance from existing transmission assets.

The move to market-based provision of generation services is not matched on the transmission and distribution side. Network interactions on AC transmission systems make it impossible to have separate transmission paths compete.[1] Hence, transmission and distribution will remain regulated. Transmission and generation heavily interact, however, and transmission congestion can prevent specific generation from getting to market. Transmission expansion planning becomes an open process with many interested parties. This open process, coupled with frequent public opposition to transmission expansion, slows transmission enhancement. The net result is greatly increased pressure to extract more and more performance from each transmission asset. For-profit RTOs may flourish, but they will be profit-motivated organizations under incentive-based regulation. The performance pressure on transmission is therefore different, but no less than the pressure on generation. More is being demanded from the transmission system now than ever before. And this trend is expected to continue. Transactions are going longer distances, in less predictable ways. System operators used to be able to restrict transactions to those that were studied ahead of time or that respected expected future trends. Now transactions are accepted as they are presented by the market.

Transmission is not expanding at the rate generation and load are expanding. The North American Electric Reliability Council (NERC) reports a 16 percent decline in the number of miles of transmission lines per MW of summer demand from 1989 to 1997. NERC expects an additional 13 percent decline by 2007 (NERC, 1998).

Transmission expansion has not kept pace with load and generation growth.

Transmission expansion is not keeping up with load and generation for three reasons. First, it is hard (and has been for some time) to build transmission for environmental and political reasons. Second, the nature of AC transmission (the network interactions, lack of control, the fact that enhancements often eliminate the locational price signals that are needed to generate revenue) makes it difficult to attract private investment. Consequently, transmission remains

[1] Widespread use of FACTS and DC links would make this possible, but they are currently too expensive for widespread use.

regulated and cannot attract speculative capital. Third, transmission is capital-intensive, long lived, with low operating costs. It can be amortized over decades. It is difficult to change the transmission system rapidly to respond to fast changes in generation, load, and trading patterns that can result as relative fuel costs change, populations and commercial enterprises move, or the economy shifts.

There is also an interesting divergence in the time required to plan and deploy transmission and generation enhancements. Technological changes (the trend to smaller, gas-fired generators) and the privatization of the investment process are accelerating generation deployment schedules. Simultaneously, transmission enhancement deployment schedules are being slowed because the processes are becoming more public and more contentious and because of land use concerns. The problem compounds because transmission planners are no longer simultaneously planning generation expansion (that is now in private hands), and they now must wait until the private generation developers make their plans known.

The net result of these trends is that there is increasing commercial pressure to move more transactions greater distances over a transmission system that is shrinking relative to the size of the load it serves. This may be accomplished by directly monitoring parameters that indicate how equipment is being loaded (e.g., line current, ambient temperature, wind speed) or by monitoring the result of that loading (e.g., line tension, sag, or equipment temperature). Sensors, communications, and control that allow the transmission system to deliver greater response and devices that allow system operators to drive lines, transformers, and other transmission elements closer to their limits could increase capacity utilization of the transmission system.

Devices that likely warrant attention include the following:

- transformers: actual measurement of transformer hot spot or other parameters, such as oil degradation
- overhead lines: sag, tension, conductor temperature, air temperature, wind, gallop
- cables: temperature, insulation
- circuit breakers: SF_6 analysis, oil analysis

3.3.2 Service Quantification

Restructuring will likely end with deregulated generators operating in competitive markets. RTOs will operate the power system, but they will be independent of commercial interests. They will facilitate commercial markets for energy and ancillary services and will purchase ancillary services themselves from competitive markets to support operation of the power system. The services themselves must be quantified for these transactions to be effective. This requires service definitions, standards, metrics, and measurement.

3.3.3 Reliability Criteria

Changes in how reliability is maintained closely parallel changes in commercial market development. In fact, they are the same thing because reliability and commerce cannot be separated. In the past, each control area (generally each utility) was responsible for maintaining reliability within its franchise service territory. Each was judged by its state regulator. Control areas interconnected to increase reliability by obtaining assistance from each other when their system was under stress. By interconnecting two control areas, utilities could share generating reserves, for example, by reducing the amount of reserves each has to carry while increasing the reliability of each.

As a result of the 1968 Northeast blackout, utilities voluntarily created regional councils and NERC. NERC and the regions helped utilities decide what reliability actions were appropriate by developing reliability guidelines. While each utility still had responsibility for reliability in its control area, and performance was still judged by the state regulator, a utility could point to the use of NERC and regional council planning and operating guidelines to justify that the utilities' actions were appropriate in spite of the inevitable power outages or to justify reliability-related expenses.

NERC is responding to restructuring by changing its name to NAERO (the North American Electric Reliability Organization) and by converting the voluntary guidelines to mandatory quantifiable policies. The process is not complete; it is not clear yet where NAERO will derive the required authority to enforce policies. Still, it is clear that a restructured industry does require reliability rules that are explicit, quantifiable, and enforceable (or priced).

As with unbundling of commercial functions, restructuring of reliability responsibilities changes from primarily relying on a judgment of the holistic system response and cost to quantification and assessments of individual performance during individual events.

3.3.4 Real-Time Electricity Pricing

Electricity is a unique commodity in that instantaneous production and consumption must be balanced continuously. Consequently, the instantaneous cost is quite volatile.

Electricity is a unique commodity in that instantaneous production and consumption must be balanced continuously. Consequently, the instantaneous cost is quite volatile. Historically, loads were shielded from this volatility and saw only average prices. Some loads saw prices that changed seasonally; some saw prices that reflected a predetermined time of use. Generators themselves were shielded from price volatility and simply operated when instructed to do so. Only the system operators were particularly aware of the cost volatility because they dispatched generators based on the generators' production cost and the system's marginal cost.

Real-time markets require faster metering and communications than are required to support average pricing and central command-and-control generation dispatch.

Restructuring is changing this indifference to real-time costs and prices. One of the major differences is the switch from cost-based transactions[2] to price-based transactions.[3] Clearly, prices and costs are normally related, but the linkage is not absolute. Active spot markets now exist for real-time pricing of bulk power transactions. Power exchanges exist in several locations that clear transactions based on buy and sell bid prices. The introduction of merchant power plants and price-sensitive loads has extended the real-time price sensitivity to individual generators and consumers, as would be expected in a mature market. Typically, transaction prices are held for 1 hour, but California is experimenting with transaction periods of 10 minutes or less. Clearly, real-time markets require faster metering and communications than are required to support average pricing and central command-and-control generation dispatch.

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[2]Economy transactions, where power was sold from one utility to another at the average of the two utility's marginal production costs (allowing each utility to capture one-half the value of the exchange) used to dominate the interchange market.

[3]With price-based transactions, power is sold at whatever price the two parties agree on.

3.3.5 Unbundling of Ancillary Services

Restructuring has brought separation of services (unbundling) as well as separation of suppliers. Ancillary services (FERC's term or Interconnected Operations Services, NERC's term) are reasonably well defined conceptually. These are services that are required to assure reliability and/or to facilitate commerce. Table 3-1 provides definitions for the 12 ancillary services. At least six of these services require measuring specific performance from the individual resources providing or consuming the service: regulation, load following, voltage control, contingency reserve—spinning, contingency reserve—supplemental, and backup supply. Most also require communication of control signals to inform the resource of the desired response. Dynamic scheduling also requires measurement and communications.

Each of the services requires a metric as well as a measurement. Regulation, for example, is the service that compensates for fluctuations in load and unintended fluctuations in generation. The system operator contracts for generating capacity that can maneuver rapidly to compensate for these fluctuations and keep the system in balance. Figure 3-1 shows the automatic generation control (AGC) signal from the system operator requesting generator response and the unit's actual performance. Figure 3-2 shows a similar plot for a unit that is not performing well. Note that even in Figure 3-1 the generator is not performing perfectly. The degree to which the supplier is delivering the service must be measured. This could be related to the difference between the time series of requests and the actual generator outputs. A metric that converts these differences into an appropriate gauge of service provision needs to be developed.

One common feature of each of these ancillary services is that service provision requires controlled behavior over time frames that are significantly shorter than the time frames over which traditional revenue metering operates. Ancillary service time frames are shown in Figure 3-3. The importance of measurement and quantification of real-time service provision or consumption is heightened by the volatility of ancillary service prices, as shown in Figure 3-4.

Table 3-1. 12 Ancillary Services and their Definitions
Time is an important factor in defining ancillary services.

Service	Definition	Time Scale
Services FERC requires transmission providers to offer and customers to take from the transmission provider		
System control	The control-area operator functions that schedule generation and transactions before the fact and that control some generation in real-time to maintain generation/load balance	Seconds to hours
Voltage control from generation	The injection or absorption of reactive power from generators to maintain transmission-system voltages within required ranges	Seconds
Services FERC requires transmission providers to offer but which customers can take from the transmission provider, buy from third parties, or self-provide		
Regulation	The use of generation equipped with AGC to maintain minute-to-minute generation/load balance within the control area to meet NERC control-performance standards	~1 minute
Contingency reserve—spinning	The provision of unloaded generating capacity that is synchronized to the grid that can begin to respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes to meet NERC's disturbance-control standard	Seconds to <10 minutes
Contingency reserve—supplemental	The provision of generating capacity and curtailable load used to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes[a]	<10 minutes
Energy imbalance	The use of generation to correct for hourly mismatches between actual and scheduled transactions between suppliers and their customers	Hourly
Services FERC does not require transmission providers to offer		
Load following	The use of generation to meet the hour-to-hour and daily variations in load	10 minutes to hours
Backup supply	Generating capacity that can be made fully available within 30 to 60 minutes to back up operating reserves and for commercial purposes	30 to 60 minutes
Real-power-loss replacement	The use of generation to compensate for the transmission-system losses between generators and loads	Hourly
Dynamic scheduling	Real-time metering, telemetering, and computer software and hardware to electronically transfer some or all of a generator's output or a customer's load from one control area to another	Seconds
System-blackstart capability	The ability of a generating unit to go from a shutdown condition to an operating condition without assistance from the electrical grid and then to energize the grid to help other units start after a blackout occurs	When outages occur
Network-stability services	Maintenance and use of special equipment (e.g., power-system stabilizers and dynamic-braking resistors) to maintain a secure transmission system	Cycles

[a]Unlike spinning reserve, supplemental reserve is not required to begin responding immediately.

Figure 3-1. Well-Behaved Generator Providing Regulation
The degree to which the supplier is delivering the service must be measured.

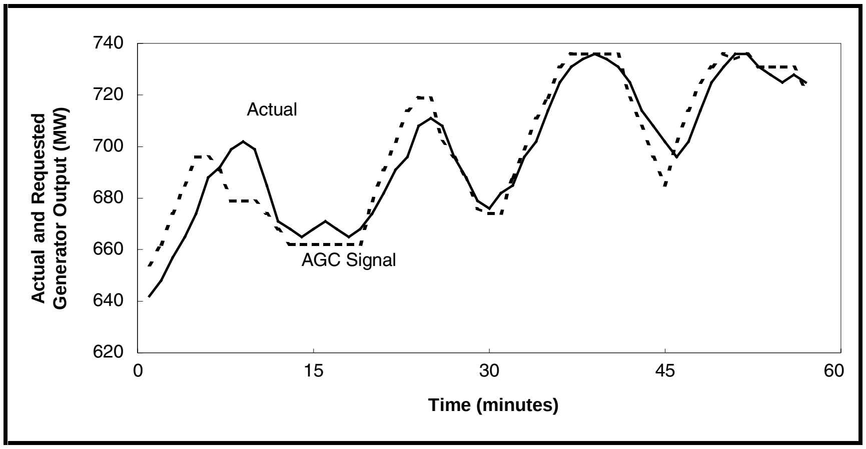


Figure 3-2. Poorly Behaving Generator Providing Regulation
Prices and enforcement contracts should provide the proper incentives and penalties when units do not perform well.

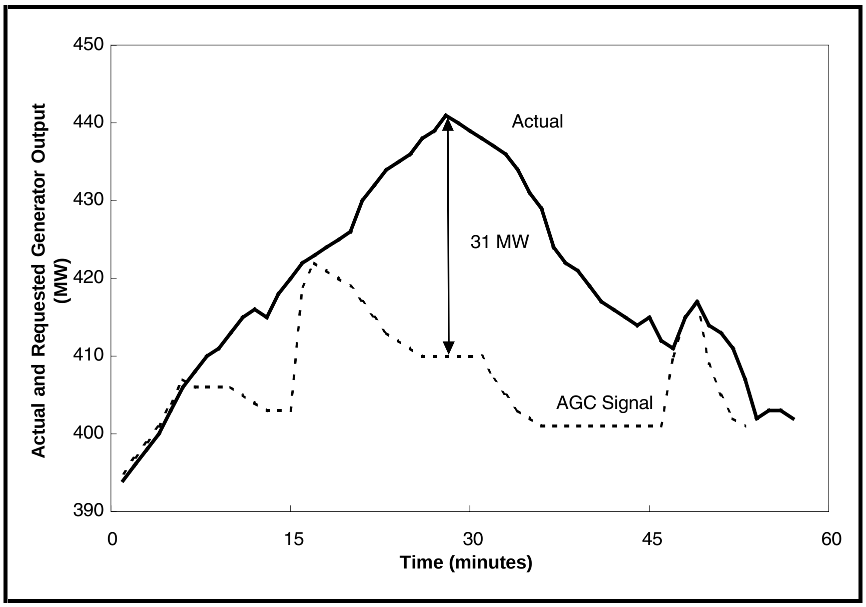


Figure 3-3. Ancillary Service Time Frames
The time frames for ancillary services vary greatly.

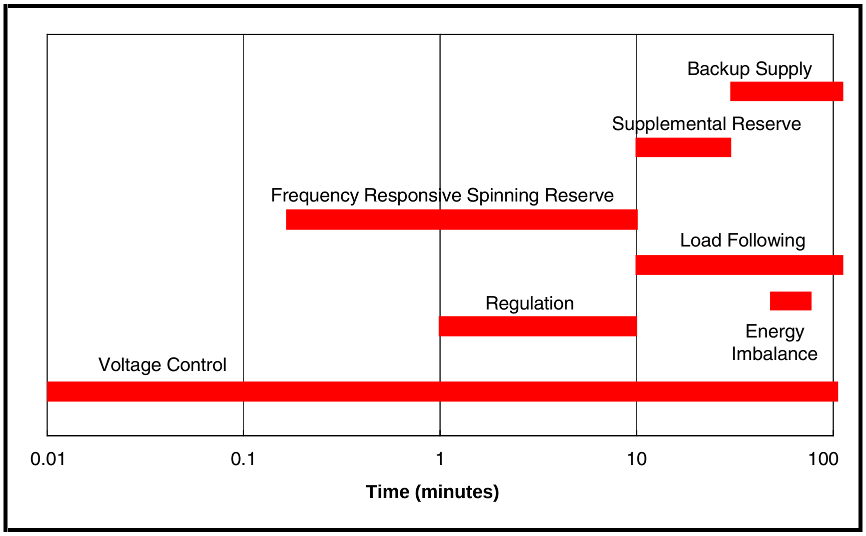
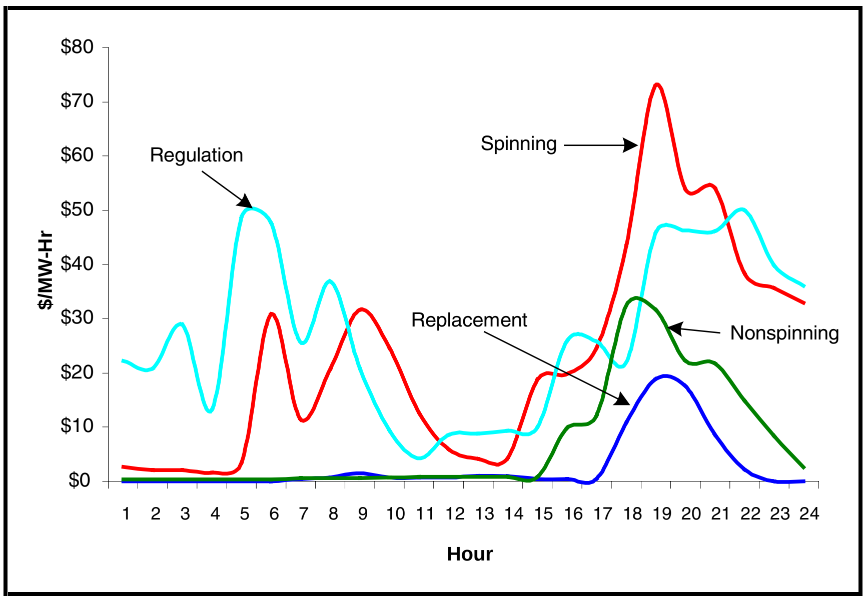


Figure 3-4. Average Ancillary Service Prices for December 1998 Weekdays in California
Real-time measurement and quantification of ancillary services is needed because of the volatility of hourly prices.



3.3.6 Reduced Generator and Transaction Sizes

> Deregulation will lead to a larger number of small loads and generators participating in real-time energy and ancillary service markets.

After nearly a century of increasing efficiency coming with increasing central generator size, there are indications that distributed micro sources may be the wave of the future. Fuel cells, micro turbines, and internal combustion engines are all vying to enter the competitive generation market. Often the primary focus is to sell energy or backup power, but it will not be long before owners and manufacturers of these devices realize that the other ancillary services may provide additional sources of income. Similarly, load can and will participate actively in real-time energy and ancillary service markets. Both trends push the size of real-time transactions down from tens to hundreds of MW to tens of kW.

This trend to active market participation by smaller resources (generators and loads) may be a tremendous boon. If loads supplied all contingency reserves (certainly possible) at times of peak usage, this would immediately free up approximately 7 percent of existing generation to serve new load. Existing emergency backup generators could supply additional thousands of MW of capacity.[4] This, in fact, was the motivation in the fall of 1999 for the Texas PUC to accelerate developing interconnection standards for distributed generation.

Most small resources have the added advantages of being agile, inherently providing fast response in real time. They are generally faster to deploy and easier to site too.

Aggregation, communications, and metering are significant obstacles to deployment of large numbers of distributed resources (generation and loads). System operators are used to dealing with a relatively small number of large resources when controlling the power system. They do not have the tools needed to communicate with large numbers of small resources. Metering presents an additional problem. It is not practical to outfit a 50 kW microturbine with the same data acquisition and telemetry suite that is typically deployed on a 500 MW steam plant.

3.3.7 Power Quality

Restructuring does not inherently change either the vulnerability to poor power quality or the importance of maintaining high power quality. However, the increasing use of sensitive electronic devices and power electronics in both loads and distributed generation will lead to power quality issues. There is an increasing need to be able to locate sources of harmonics and flicker on the power system.

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[4]There is considerable debate over the exact number.

There will probably be a need to regularly monitor large numbers of locations on the power system.

3.3.8 Supplier Choice

Providing end users with the flexibility to choose their power supplier may entail significant technical challenges. Generally supplier choice is limited to the source of bulk energy. If customers could be tied more closely to their chosen suppliers, through the existing network, additional market efficiencies would be tapped.[5] For example, a customer could choose a lower cost, lower reliability supplier. The customer would see increased interruption but pay a lower price for electricity. Alternatively, a customer could pay a higher price for added reliability. This would allow individual customers to balance reliability and price, providing clearer market capacity expansion signals.[6]

3.4 CONCLUSIONS

The final form of a restructured electric power industry is far from clear. It is likely that regional differences will persist. Several trends appear to be well established:

- Reliance on commercial provision of services requires increased metering, communications, and control capability.
- Individual transactions will increase in importance, and metering must accommodate smaller transactions and smaller entities (both loads and generators).
- Individual real-time services will be unbundled. Revenue metering must accommodate faster transactions and comparisons between requested and delivered responses.
- Increased response will be required from the transmission system, and technologies that allow the transmission system to provide increased responses will have value.

[5] This would be the equivalent of dynamically scheduling each load to its chosen supplier.

[6] This would only address generation-related reliability or *adequacy* issues. It would not address distribution reliability issues, which account for most residential outages. Still, generation adequacy and expansion are major concerns.

The metering, communications, and control requirements of a restructured electric power industry appear to be more related to the fundamental change of increasing reliance on markets and contracts and decreasing reliance on regulation and vertical integration than they are on the specific restructuring implementation.

The metering, communications, and control requirements of a restructured electric power industry appear to be more related to the fundamental change of increasing reliance on markets and contracts and decreasing reliance on regulation and vertical integration than they are on the specific restructuring implementation. Similarly, the need to extract more performance from the transmission system is related to the difficulty to construct transmission and increasing commercial pressure to use transmission, not to the specifics of how industry restructuring moves forward. As a result, the need to advance metering and monitoring technology seems to be broadly based on national requirements that are not sensitive to the details of restructuring implementation (i.e., different restructuring scenarios).

In addition, whether deregulation is examined from the wholesale or retail perspective has surprisingly little impact on the *type* of metering that is required. The *amount* of metering may be different at the wholesale level versus the retail level. Wholesale transactions may require metering only for large entities (generators and large loads) and aggregations of small entities (primarily loads) while retail transactions require metering for all entities. The *type* of metering that is required, however, depends on the service being measured, which in turn relates to physical phenomena on the power system.

The physical laws governing the power system's behavior do not change with deregulation. Accomplishing the required minute-to-minute generation and load balancing, for example, requires metering that measures energy flows at least that fast. Addressing this minute-to-minute balancing at the retail level requires more metering, not different metering than what is required at the wholesale level. Because of the difference in consequences to the power system from a failure at the wholesale vs. retail level, there may be different reliability requirements for the metering but not in what is fundamentally being metered. Similarly, it does not matter if metering requirements are examined from the supplier's or the consumer's perspective. In both cases, the same phenomena is being measured. Nor does it matter if metering requirements are examined from the FERC perspective of comparability or the NERC perspective of reliability. Again, the same underlying physical phenomena are being measured.

4 Measurement and Standards Needs to Support Restructuring

This section discusses broad measurement and standards requirements to support reliable operations and commercial transactions on the electric power system in a deregulated environment. Measurement requirements, in this context, include the basic physical measurements as well as the associated communications and control requirements.

Standards support requirements are related directly to the measurement requirements. However, they are organized here into the two categories described in Section 2: system operations and market transactions. These standards support requirements are not spelled out in detail—that is the appropriate role for the various standards organizations cited in Section 4.2.

Although systems operation (e.g., reliability) and market transactions (e.g., market development) concerns differ in many important aspects, they are also inseparable and often complementary. We surveyed a broad range of industry experts to capture the full range of concerns from the supply and demand sides as well as from the operations and planning/investment sides.

4.1 MEASUREMENT NEEDS

Measurement needs include the physical quantities that must actually be measured and the speeds at which they must be measured. We describe the underlying trends that are changing measurement requirements and examine the importance of differences among individual customers. This section also discusses measurement and control communication requirements and how these may change with deregulation. Finally, we discuss unique measurement requirements for the transmission and distribution systems.

4.1.1 Physical Measurement Requirements

Voltage and current are the two fundamental electrical quantities that need to be measured to monitor an interconnected power system.

In one sense, there are very few measurement requirements on an interconnected power system. Voltage and current are the two fundamental electrical quantities of interest. Other quantities, such as real and reactive power and energy, are derived from measurements of voltage, current, and the phase angle between the two. Phase angle itself is not really a fundamental measurement but is derived from the temporal relationship between the periodic voltage and current fluctuations (alternating current). Measuring harmonics, flicker, sags, surges, and dropouts involves measuring voltage and current over different time frames.[1] Similarly, even though consensus has not yet been reached concerning the exact definitions of the ancillary services (or the related NERC Interconnected Operations Services) discussed in Section 3, it is clear that they involve measuring real and reactive power delivery and consumption over various time frames.

Table 4-1 presents the measurement requirements for a range of services of interest under wholesale and retail power deregulation. Note that, although the time frames presented are typical, exact requirements vary from location to location depending on the way each service is defined. Also note that the reporting time frame is listed as “periodic” for all of the services because it is not strictly necessary for the system operator to directly observe the response of each resource supplying reliability services in real time.

The wide range of voltages involved in the electric power system complicates the measurement of voltage and current. Transmission line voltages are up to 765 kV (nominal line-to-line voltage), but

[1] The unique nature of power quality issues such as flicker, harmonics, sags, surges, and dropouts may warrant individually designed meters for each. Still, they are only measuring voltage and current.

Table 4-1. Measurement Requirements Under Deregulation
Services are differentiated by the time frame over which the service must be deployed and measured and the response reported.

Service or Concern	Product Attributes	Measurement Time Frame	Deployment Time Frame	Reporting Time Frame
Power Quality				
Harmonics	Voltage and current	<1 second		Periodic measurement when problems are reported
Flicker, sags, surges, dropouts	Voltage	~1 second		
Ancillary Services				
Regulation	Watts	~1 minute	~1 minute	Periodic
Stability	Watts and/or vars	<1 second	<1 second	Periodic
Contingency reserve—spinning	Watts	Seconds	Seconds	Periodic
Contingency reserve—supplemental	Watts	<10 minutes	<10 minutes	Periodic
Load following	Watts	~15 minutes	Minutes	Periodic
Backup supply	Watts	~30 minutes	Minutes	Periodic

even the 13 kV of typical distribution systems is too high for most direct electronic measurement. Currents are generally too high for direct measurement, both at the elevated and the lower voltages.

Voltage transformers, which are often referred to as PTs (for “potential transformers”), are used to scale the voltage of interest down to a more easily measured range. Current transformers (CTs) are used to both scale the electric current of interest down to a more reasonable range and to extract the electric current signal at a voltage much closer to zero than line potential. PTs and CTs are not to be confused with power transformers, which are very large. PTs and CTs are expensive, and careful attention must also be paid as to how these devices distort the measurements being made.

Measurement Synchronization

Time synchronization is very important for some measurements. The Wide Area Measurement System (WAMS) uses precisely synchronized measurements of voltage and current (real and reactive power and voltage) collected from locations dispersed over large geographic areas to observe the dynamic behavior of the power system. This is particularly important in the Western System Coordinating Council (WSCC).

Temporally synchronizing data is also a concern with more conventional measurements. Many conventional system control and data acquisition (SCADA) systems collect data by sequentially polling the sensors on the system every few seconds. Measurements obtained from sensors polled early in the cycle are not synchronized with measurements obtained from sensors polled late in the cycle. This is especially problematic if a significant event occurs during the cycle and the system operator (or automatic control equipment) is trying to understand what has occurred. For example, flows might be different at two ends of a transmission line because the line is damaged or one measurement was taken before a generator tripped and the other was taken after it tripped. This problem increases as additional commercial entities start to handle data and as equipment from multiple vendors is used. Some form of time-stamping the data may be needed.

Additional Measurements

Most electrical devices are inherently temperature-limited because the device's electrical resistance generates heat as current flows through the device.

A number of other parameters are measured to ascertain the present capability or status of the transmission system. For example, most electrical devices are inherently temperature-limited because the device's electrical resistance generates heat as current flows through the device. Excessive heat can cause instantaneous failure or shorten equipment life.

Equipment capacity ratings (e.g., the power flow capacity of transmission lines or transformers) are often based on the temperature that will result at some critical component under specific environmental conditions such as ambient temperature and wind speed. The device might actually have more or less capacity under different environmental conditions. Directly measuring the temperature of the limiting component could allow higher utilization of transmission capacity without compromising safety.

Historically, measuring the critical temperature has been difficult because knowing exactly which component is critical and making measurements on energized equipment are difficult tasks. For example, determining which span of a transmission line is the limiting span depends on the direction of the wind and the limiting span may change with cloud cover. The electrical environment makes determining the temperature inside a 345kV cable and transmitting that information to the system operator much more difficult.

> Direct measurement of ambient line conditions would help to more accurately estimate current limits and increase utilization of transmission assets.

Overhead transmission lines are thermally limited because heat allows the conductor to expand. If the conductor gets too hot, it will permanently weaken or fail. Most lines reach a sag limit (i.e., the conductor lengthens enough that the center of the span is too close to the ground or to structures under the line) before the conductor is permanently damaged by heat. Limits for current are established for most lines based on the sag calculated to result from that current under specific assumptions of ambient temperature and wind. Limits could be based on direct temperature measurements instead allowing line loadings to be raised until the line is truly at its physical limit. Alternatively, sag could be measured directly, or line tension could be measured to calculate sag.

Status measurements on numerous devices throughout the power system are also required. Breaker and switch positions are important. Generator status is important. Many system operators require reporting generator capability regularly, either by direct measurement or by the generator operator updating the capability. Supplemental information, such as hydrogen pressure, is often required to be sensed and reported directly to the system operator.

4.1.2 Underlying Trends Changing Measurement Requirements

Three interrelated forces are driving the need for clearer definitions of service requirements and an increased need for measurements and communications:

- Reliance on commercial arrangements (contracts) between service suppliers and the system operator requires clearer definitions of the services being provided than was needed with vertical integration.
- Unbundling of individual services (e.g., regulation, contingency reserves) requires defining each service and measuring performance.
- The introduction of competition to replace regulated monopolies requires more explicit and definitive service definitions and performance measurements that can be reflected in contracts.

These three interrelated forces dramatically change the measurement requirements even when there are no physical changes in the power system. Many more measurements at many more locations are required to assure that specific contracted services are being provided. A competitive commercial entity may not deliver a service if delivery is not monitored. If an honorable entity does deliver the unmonitored service, a less ethical competitor may undercut the service price and win the next contract, because its price need not cover the cost of actual delivery.

Physical changes in the power system compound the increased measurement requirements. Changes in the size of generators, the inability to build new transmission, and the potential for customer loads to enter the ancillary service markets as suppliers all contribute to an increased need for measurements. Fortunately, the enabling technologies of computing, communications, and electronics are getting dramatically cheaper, so that the additional measurement requirements will not be cost prohibitive.

Physical Changes in the Power System

Technological advances are changing the measurement, communications, and control requirements of the power system as well. These advances are primarily tied to the resources that are available to provide energy and reliability services.

- Generators are getting smaller. After a century of ever-increasing efficiency coming with ever-increasing size, we are seeing that trend reverse, perhaps dramatically. This trend is coupled with the availability of competitively priced natural gas as a power generation fuel. Until recently, unit sizes were increasing above 1,000 MW to achieve greater efficiency. Now, combined-cycle units, which use combustion turbines and gas boiler technology in the 50 to 300 MW range, have impressive thermal efficiencies (some claim to be near 60 percent). We are also seeing microturbines less than 100 kW range nearing commercial viability. Internal combustion-driven generator efficiency is increasing dramatically as well. Especially at times of high peak prices, we will likely see numerous generators in the <100kW size in use at customer sites.
- Replacing a 1,000 MW generator with multiple, smaller (e.g., 10,000 100 kW) generators raises concerns about the cost of metering and data communications as well as concerns about data overload. Replacing a 1,000 MW

generator with multiple, smaller generators also changes the risk assessment for failure of the resource to perform. This changes the assessment of metering and data communications needs related to assuring system reliability.

➤ The introduction of demand-side elasticity (price-responsive load) and load as a resource selling reliability reserves to the power system compounds this problem because the sizes of the individual loads that are price-responsive may be very small.

➤ Advances in electronics, computing, and communications need to be exploited to reduce costs and increase the opportunities for these resources to participate in electricity and reliability service markets.

Precision and Traceability

Deregulation, corporate unbundling, and the introduction of competition change the precision and traceability requirements of measurements. Currently, revenue metering for energy is distinct from operational metering. Revenue metering is generally more precise, meets tighter standards, and has better traceability to primary standards. Revenue metering is also more expensive and generally does not operate as fast as operational metering. It generally deals with energy consumption over 15 minutes or an hour. Operational metering, on the other hand, is used by the system operator to facilitate control of the power system. And traditionally systems have had sufficient margins so that it is not necessary (or economical) to precisely measure all performance parameters. However, as safety margins shrink with the cost-cutting pressures of deregulation, the precision of operational metering may need to increase. Traceability and precision are not as high a concern. Redundancy in the metering and state estimation increases the operator's view of the overall system without increasing the cost of individual measurements.

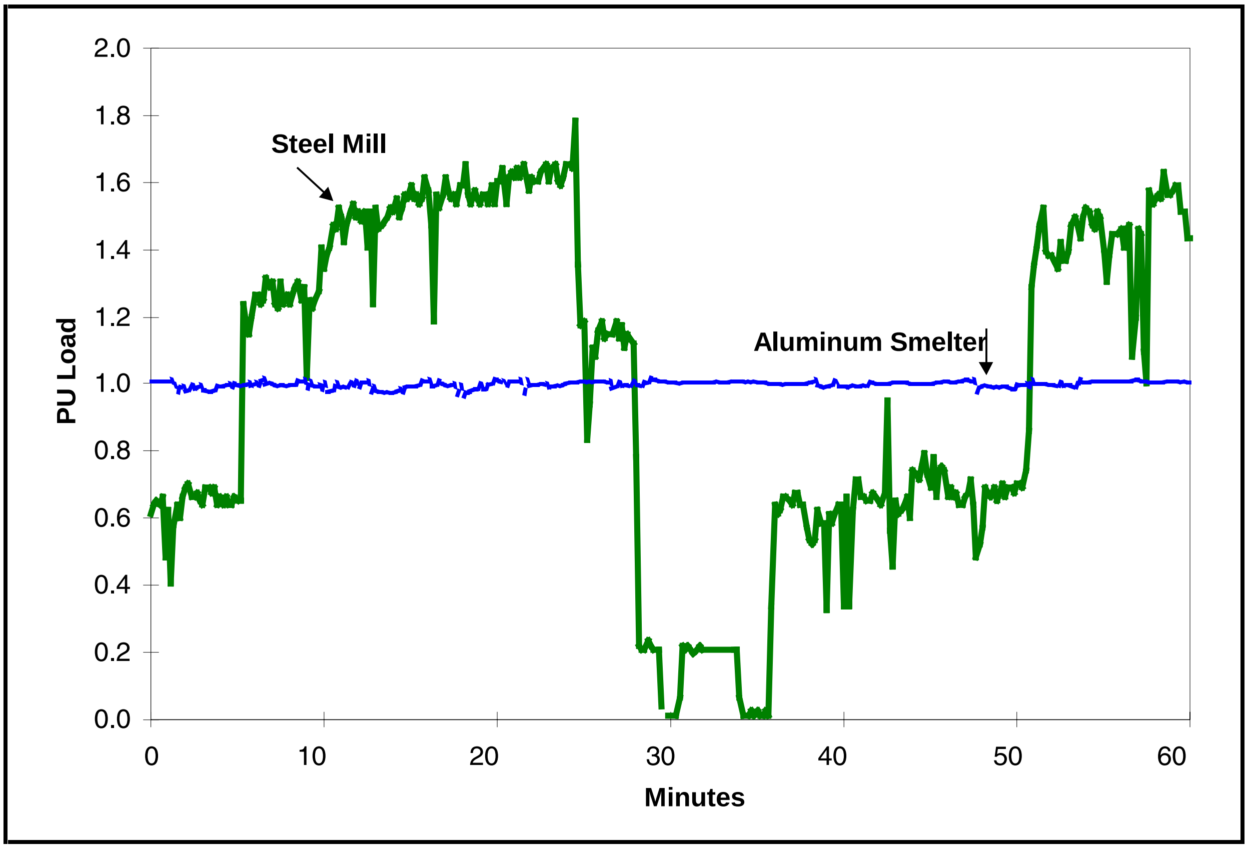
With deregulation and unbundling of services, the scope of revenue metering greatly increases.

With deregulation and unbundling of services, the scope of revenue metering greatly increases. Many more activities that generators previously performed on command by a system operator that "owned them" will now need to be compensated for based on measured performance. As a result, meter quality (precision, speed, and reliability) is an important commercial issue for many more measurements.

4.1.3 Customer Differentiation

It has long been recognized throughout the industry that different customers impose different requirements on the power system. Figure 4-1 shows the power consumption for a steel mill and an aluminum plant for an hour. Clearly, the steel mill is imposing a significantly greater regulating burden on the power system than the aluminum mill. Historically, this difference was addressed through the bundled rate offered to each customer by the vertically integrated utility. That rate might, or might not, accurately reflect the total cost to serve each customer. Deregulation is changing how individual customers are treated.

Figure 4-1. Individual Loads Impose Different Regulation Burdens on the Power System
Under deregulation, customers will be charged for the different burdens their loads place on the system.



FERC recognizes that customers use different amounts of ancillary services as well as different amounts of energy and capacity. In a recent Notice of Proposed Rulemaking, FERC states "The Commission believes that, whenever it is economically feasible, it is important for the RTO [Regional Transmission Organization] to provide accurate price signals that reflect the costs of supplying ancillary services to particular customers" (FERC, 1999). Similarly, in Order 888 FERC states that because customers that take similar amounts of transmission service may require different amounts of some ancillary services, bundling these services with basic transmission service would result in some customers having to take and pay for more or less of an ancillary service than they use. For these reasons, the Commission currently concludes that ancillary services, such as system control, voltage control from generation, regulation, contingency reserve-spinning, contingency reserve-supplemental, and energy imbalance, should not be bundled with transmission service.

> With deregulation, it will be increasingly important to assess each entity for the individual support it provides or burden it places on the power system.

Differentiation among individuals is not limited to loads or regulation. Analysis of data from specific generators indicates that they impose very different reliability reserve requirements on the power system, as shown in Figure 4-2. Similarly, analysis of data from specific generators indicates that they provide very different regulation support to the power system.

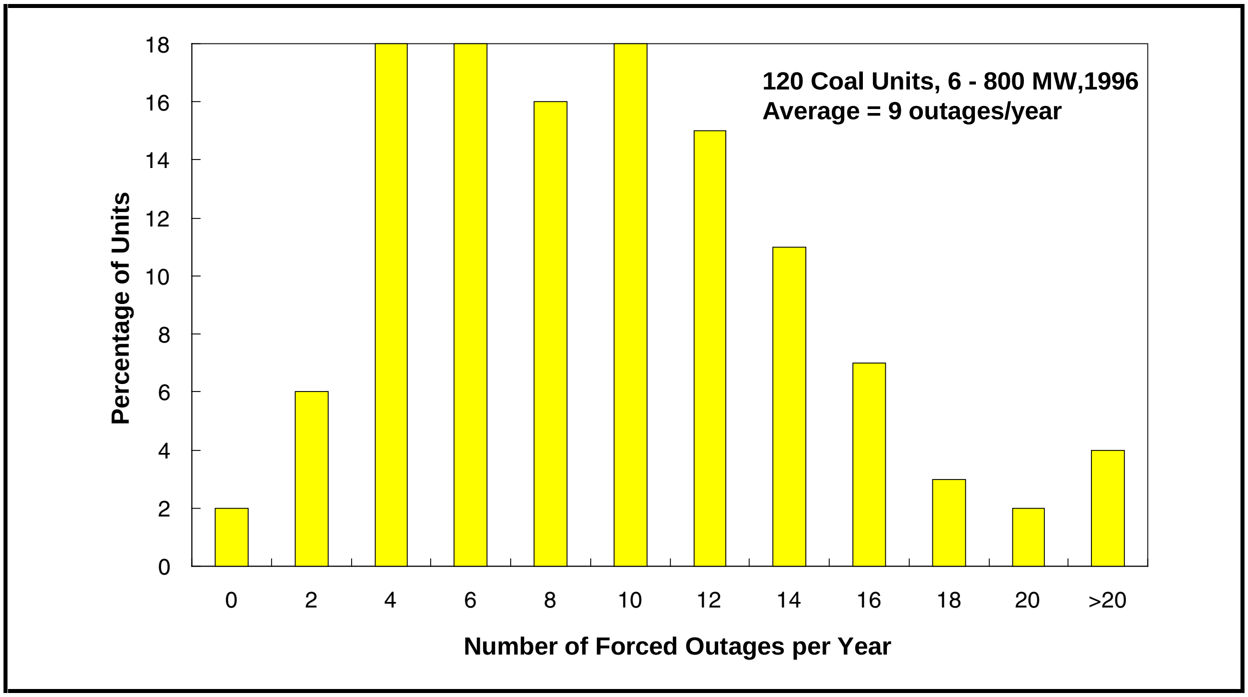
All of this supports the need to assess each entity for the individual support it provides or burden it places on the power system. Metering is required to make this assessment and to respond at the appropriate rate for each service. This change means a large increase in metering and data processing requirements.

4.1.4 Communications

Communications requirements also need to be re-examined. Like measurement speed requirements, communications requirements are tied to the service being provided and the function being performed. Communications requirements in both directions (system operator to resource and resource to system operator) must be addressed separately.

Historically, the system operator dealt with relatively few large generators. SCADA systems were designed on the basis that information was collected every few seconds by polling each data collection point throughout the system. Techniques to reduce the quantity of data, such as reporting only status changes, were used.

Figure 4-2. Individual Generators Impose Different Reliability Burdens on the Power System
Under deregulation, individual generators will be held responsible for the different reliability burdens they impose on the system.



Commands were sent to generators and a generator's output was observed every 2 to 8 seconds (depending on the utility) to see if the generator was responding. This system worked well and made sense for large generators. It is not clear if this is the best system for numerous small generators or for responsive load, however.

The basic requirement to get command signals from the system operator to the resource quickly still exists. Very fast signals, based on local conditions or system frequency, do not have to come from the system operator; they can be locally derived. Response must also be monitored in the same fast time frame. It may *not* be necessary, however, to send the response signal back at the present rate. It might be better to monitor performance locally and report back at the end of the billing period. The system operator would still be aware of the aggregated (total system) response, but the individual composition of that response would not be immediately available.

System operations, however, may be improved with increased number of suppliers because the reduced size of each individual supplier reduces the consequences of individual failures to respond. It might be easier to predict the statistical behavior of a large fleet of smaller resources than a small fleet of larger resources.

4.1.5 Transmission

Transmission (and distribution) will likely remain regulated and will be shielded from some of the commercial pressures that generation and load will experience. However, measurement, communications, and control requirements for transmission will change too.

Independent of deregulation, increasing public opposition to new overhead transmission lines makes increasing transmission system capacity through new construction difficult.

Independent of deregulation, increasing public opposition to new overhead transmission lines makes increasing transmission system capacity through new construction difficult. Deregulation compounds this problem by making it more difficult to argue that transmission is built exclusively for reliability reasons and then to use power of eminent domain to obtain right-of-way. Under deregulation, transmission is built largely for economic reasons, when it provides a better economic choice than locating additional generation closer to the load. The shift from reliability to profit for the justification of new transmission corridors increases the difficulty of building new transmission capacity when public approval is required.

Separating transmission and generation also makes solving transmission operating problems (overloads) with traditional generation solutions (redispatch) more difficult. With a vertically integrated regulated monopoly, a transmission loading problem could be solved by redispatching generation with all customers paying the increased costs associated with off-economic dispatch through slightly higher average rates. Now, individual generators have a strong interest in restrictions on their operations and will oppose curtailments in their individual operations based on transmission loading. This problem is compounded by the increase in the number of transactions occurring.

All of this results in increasing transmission loading, little ability to install new capacity, and difficulty in using redispatch to alleviate transmission congestion. Extracting increased performance from the existing transmission system is an important alternative.[2] Improved measurement capabilities are needed to increase performance.

- Better measurement of actual conditions is required to provide the system operator with a more accurate picture of how close the system is to real limits. This picture includes a more complete picture of the electrical activity on the power system as well as a more complete picture of the equipment conditions. For example, real-time monitoring of line and transformer temperatures can help provide this more complete picture.
- Increased ability to measure system dynamic performance and to evaluate contingency situations is required to allow the system operator to operate closer to the system dynamic limits while maintaining or increasing reliability. Increased use of WAMS and voltage security calculations could help.
- Increased capacity to manage market transactions is needed. Systems that relieve the system operator's administrative load, reduce errors, and make inputting and tracking transactions easier are required. These systems may include software to support user-friendly interfaces and display systems to enhance human–machine interactions.

The benefits of these developments are not only to maintain existing levels of system reliability. They also include increases in the effective capacity or transfer capability of the system, increased efficiency of operation, and reduced administrative costs of serving a larger number of more diverse transactions.

4.2 AREAS WHERE STANDARDS MAY HAVE MAJOR BENEFICIAL IMPACTS IN A DEREGULATED UTILITY INDUSTRY

As described above, several issues are emerging as electric industry deregulation proceeds. Several of these issues may benefit from the development of standards by standards committees at the industry, professional society, regulatory agency, or other levels.

Some examples of organizations that can and may currently be contributing to the development of these standards are

- Institute of Electrical and Electronic Engineers (IEEE),
- National Electrical Manufacturers Association (NEMA),

[2] Other alternatives include placing distributed generation nears loads and increasing use of load management programs.

- American National Standards Institute (ANSI),
- North American Electric Reliability Council (NERC) (or its successor, North American Electric Reliability Organization [NAERO]),
- Edison Electric Institute (EEI),
- Electric Power Research Institute (EPRI),
- Federal Energy Regulatory Commission (FERC),
- National Association of Regulated Utility Commissioners (NARUC),
- states (regulators and/or legislators),
- National Regulatory Research Institute (NRRI), and
- NIST.

This list of organizations is illustrative, not all-inclusive. Standards committees that include representatives from one or more of these organizations will help to integrate a diverse set of issues and considerations into the standards development process. Such committees may also help build a broader base of acceptance for the standards that are developed.

> The key driver behind the potential value of standards in a deregulated electric industry is the change from a vertically integrated structure to one that relies on competitive markets to supply critical reliability services.

We have separated opportunities for standards into those to support system operations and those to support market transactions. This separation is made for expositional convenience and because the key "users" in each of the two are different. However, the two areas are not mutually exclusive because reliability and commerce are not mutually exclusive. Thus, some of the opportunities mentioned in the first area may benefit the second, and vice versa.

These opportunities are a summarization of the needs for standards cited by respondents to our survey. A copy of the survey instrument is presented in Appendix C. A listing of these responses by type of respondent and by response area is included as part of the full range of notable comments provided by survey respondents in Appendix D.

4.2.1 Opportunities for Standards to Support System Operations Needs

The contributions of standards in support of systems operations will primarily be to help system operators maintain system reliability in the face of expanded and more complex transactions and power flows. Standards may also contribute to the reliability of the system operators themselves by helping them manage and act on the expanded flow of information. Well designed, performance based standards can lower costs as well as increase reliability by encouraging innovation and allowing markets to find the most cost effective way to provide needed reliability services.

Some key areas where technology standards may contribute to the needs of system operators include the following:

- ➤ standardization of information availability requirements will be important to support competition. Currently some purchasers have a competitive advantage because of asymmetric information;
- ➤ expanded and more frequent measurement and communication of system conditions (e.g., operational status of key equipment and components, real-time monitoring of line and transformer temperatures, online transfer capability evaluation) to system operators;
- ➤ measurement and communication of transmission system dynamic performance (e.g., system transient behavior, WAMS, and monitoring of voltage collapse) to system operators;
- ➤ more frequent measurement and communication of distributed generators' output (aggregated) to system operators. For example, standards are needed to increase the amount of information returned from generation. In particular, system operators need better information of the timing of loads being generated;
- ➤ dynamic control of distributed generation to maintain system reliability and to access potential ancillary service benefits;
- ➤ measurement and communication to system operators of ancillary services provided by generators (utility and merchant plants) and customers (though onsite generation or load curtailment);
- ➤ security requirements to maintain system integrity as the market opens up and the number of players increases; and
- ➤ enhanced software to help system operators manage the increased data flows, calculate key system parameters of interest, and present the information in a manner that avoids information overload and facilitates quick decisions.

A central theme throughout our interviews was that industry should move away from prescriptive standards and toward performance based standards. In addition, particular standards should not be built around existing system characteristics because this stifles innovation by locking in technology-based solutions. Standards are needed to establish a minimum set of functionality. Establishing functionality standards will promote competition and lower barriers to entry.

Interviewees also emphasized that interoperability and conformance testing of communications protocols are essential to support the integration of area systems.

Interviewees also emphasized that interoperability and conformance testing of communications protocols are essential to support the integration of area systems. In addition, product conformance is important because without it products might have trouble interconnecting in a network or even fail in performing basic operations. In some instances, regulations and standards are in place, but there is no enforcement. For example, there are currently standards for equipment accuracy in many states; however, state agencies do not have the budget for compliance testing and enforcement.

4.2.2 Opportunities for Standards to Support Market Transactions Needs

The contributions of standards in support of market transactions will primarily be

- to help assure interoperability among equipment and systems provided by different vendors and to help provide reliable and precise information for contracts (e.g., billing, performance measurement and verification) and dispute resolution and
- to help develop pricing systems that reflect proper incentives and to support development and enforcement of noncompliance penalties.

Growth in metering, monitoring, and communications needs within the industry is spawning, and will continue to spawn, more vendors and equipment. This growth can increase the risk of lost opportunities with deregulation to the extent that the equipment and systems cannot "cross-talk" effectively and provide the full range of information needed by each new market player.

The contracts support function is necessary because explicit contracts are increasingly replacing informal agreements. This trend is a result of the change in industry structure from regulated, integrated electric utilities who coordinate their efforts primarily though informal agreements, to functionally unbundled electric utilities who compete in the provision of generation, ancillary services, and retail services. Competition requires explicit contracts to facilitate coordination and cooperation.

Contract support here differs from system operator support described in Section 4.2.1, not only in terms of the type of information required and at what level, but also in terms of how frequently it needs to be provided. Contract support will typically require information on a more disaggregated level (e.g., for individual loads rather than for entire substations), rather than monthly readings of these values, etc., but the information is typically communicated less frequently (e.g., monthly rather than hourly or subhourly).

Standards will be needed to provide proper pricing signals for transmission services.

Standards will be needed to provide proper pricing signals for transmission services. For example, new tools/procedures are needed to help the market value power at bulk transmission interfaces. These include new measurement and reporting procedures to collect and distribute information on utilization of these interfaces. Some interviewees said that the existing pricing systems for bulk transmission provide incentives for congestion.

Some additional areas where technology standards may contribute to the smooth functioning of wholesale and retail markets include the following:

- creation of a seamless electronic data interchange (EDI) between metering and communication software and equipment, so that retail market players (e.g., generation suppliers, local wires utility, aggregators, billing companies) can obtain the various data they need when they need it;
- consideration of standards and protocols for EDI that reflect the growing use of the Internet (and the Internet Protocol, or IP) to link services across utility providers (the "convergence" trend) and cover international borders (the "globalization" trend);
- tracking of generator supply: whether and when they supplied generation or ancillary services to the system as required by contracts;
- tracking of retail customer and power marketer/broker curtailments: whether and when they supplied load relief or ancillary services to the system as required by contracts;
- tracking/tagging of power flows to assign cost responsibility for congestion on overloaded lines and constrained interfaces;
- more precise measurement of standard billing parameters (e.g., energy, demand, power factor) to support contracts that were previously not in place or that were not explicit if they were in place;
- more precise measurement of power quality, especially harmonics, flicker, sags, and surges to support contracts that were previously not in place or that were not explicit if they were in place; and

- better definitions of what is “NIST traceable.” For example, almost all metering equipment claims to be NIST traceable. However, the number of steps involved in the traceability chain influences accuracy.

4.2.3 Summary

Measurement requirements and related needs for standards development is, or needs to be, underway in several areas to help secure the benefits that are potentially available in a deregulated electric industry. We have summarized some of the key areas in this section.

The development and application of standards are not without their own costs, however, and they may lead to some adverse side effects as noted in Section 1.2. A decision on whether to pursue standards in any area requires a prospective assessment of the benefits and costs of standards for that area. Retrospective assessments of these benefits and costs are also valuable, not so much to affirm or withdraw the original decision, but to help refine the techniques and areas of investigation in assessments that will be made in the future.

5 Economic Impact of Measurement and Standards

Measurement and standards to support the electric power industry will have a potentially large impact on the U.S. economy for two main reasons:

- ➤ Measurement and standards are becoming increasingly important as deregulation proceeds.
- ➤ In 1998, U.S. electric utility retail sales of $217.4 billion represented one-quarter of 1 percent of U.S. GDP of $8,759.9 billion. Reliable, low-cost power is a cornerstone for almost every sector of the economy.

This section discusses the pathways through which measurement and standards will affect the electric power industry and, hence, the U.S. economy.

This section discusses the pathways through which measurement and standards will affect the electric power industry and, hence, the U.S. economy. The discussion is structured around 11 key issues/benefits/concerns, referred to as impact areas, associated with deregulation. For each impact area, we discuss the magnitude of the potential economic impact and the importance of measurement and standards for addressing the issues/benefits/concerns. In addition, we discuss the level of uncertainty associated both with the evolution of the industry structure and future technology developments and with the future role measurement and standards will play.

This section also presents monetary range estimates that provide insights into the potential magnitude of the economic impact (benefits) of measurement and standards in supporting deregulation of the electric power industry. The underlying insights used to develop the economic impact estimates are based on a series of scoping interviews and surveys with industry experts, and they reflect the authors' interpretation of information collected from these respondents.

5.1 PATHWAYS TO ECONOMIC IMPACTS

Table 5-1 presents some of the potential impacts of measurement and standards identified through the scoping interviews. The impacts are presented as the *benefits* associated with meeting the measurement and standards needs of the power industry (as opposed to the costs of not meeting the industry's needs).

Table 5-1. Benefits Associated with Measurement and Standards
Benefits are generally grouped relative to their impact on technical efficiency and/or clean power.

	System Operation	**Market Operation**
Technical Efficiency	➤ Alleviate transmission constraints ➤ Lower the cost of generation ➤ Lower the cost of ancillary services	➤ Lower the cost of generation ➤ Lower the cost of ancillary services ➤ Lower the cost of metering, data transfer, and data processing ➤ Provide incentives for demand-side changes (peak reduction)
Clean Power	➤ Reduce the duration and frequency of power outages ➤ Reduce the installation of backup and protective equipment ➤ Diagnose and verify power quality problems at utility and customer levels	➤ Support market for variable power reliability ➤ Support market for variable power quality

Most of the categories in Table 5-1 are interrelated. For example, efficiency gains in the form of lower-cost generation and ancillary services will require measurement and standards to support system operation and market operations. Enabling customers to access the lowest-cost electricity service will require an efficient market structure to enable transactions and the physical system to efficiently facilitate the market transaction.

> Economic impacts reflect the efficiency "gap" that results from "inadequate" measurement and standards.[1] Inadequate measurement and standards can lead to two general categories of impacts:
> - increases in the cost of supplying electric power
> - costs associated with decreases in the level of reliability and power quality experienced by end users of electricity

As indicated in Table 5-1, measurement and standards will affect both economic efficiency of the power supply and the level of reliability and quality of power. In general, economic efficiency includes achieving the lowest cost for the generation, transmission, and distribution of electric power. Cost savings can include both the reduction in variable inputs (e.g., by using more fuel-efficient generation) and the avoided cost of new capital investment (e.g., by reducing the need for new transmission assets).[2]

In contrast, power reliability and power quality, also referred to as clean power (from an end user perspective rather than from an environmental perspective), are related to factors that affect the end users of electricity. Clean power affects end users by influencing them to actively respond to changes in reliability and power quality by installing backup and protective equipment or not responding and bearing the impact of, for example, increased outages and power surges on business activities.

5.2 ECONOMIC IMPACT AREAS

Table 5-2 lists the set of impact areas that were included in the economic impact analysis. This table identifies key issues/benefits/concerns associated with deregulation of the electric power industry. For each issue/benefit/concern, the magnitude of the potential issue is indicated along with the importance of measurement and standards for addressing the issue/benefit/concern.

The impacts of high/medium/low presented in Table 5-2 are based on information obtained through telephone interviews and surveys conducted with 40 industry experts (Table 1-2 lists the affiliations of the respondents). The combination of "high" relative magnitude and "high" importance of measurement and standards, such as for

[1]Gap analysis is commonly used in the strategic planning literature to compare potential versus actual growth or efficiency gains.

[2]We do not trace these cost savings through to changes in price because determining price changes involves estimating the distribution of savings accruing to producers and consumers. And the focus of this study is on the total change in social welfare as opposed to the proportional changes in consumer and producer surplus. However, in the long run, all changes in social welfare eventually accrue to consumers in the form of changes in price or changes on the return to production assets that are owned by consumers.

Table 5-2. Impact Areas Associated with Deregulation

The impacts of high/medium/low reflect opinions obtained through interviews and surveys with industry experts.

Issues/Benefits/Concerns Associated with Deregulation	Relative Magnitude of Issues	Importance of Measurement and Standards	Variation in Responses
System Operation			
Achieving potential efficiency gains in power generation resulting from increased competition	High	Medium	Low
Adequate and efficient provision of ancillary services in a deregulated environment	Medium	Medium	Medium
Limited transmission capacity to support increasing system demands resulting from deregulation	Medium	High	High
Integrating distributed generation into the system and fully using its resource potential	Medium	High	Medium
Increased duration and frequency of power outages resulting from deregulation	High	High	Medium
Degradation in power quality resulting from deregulation	High	Medium	High
Inadequate diagnostic tools capable of monitoring system conditions and identifying problems	High	Medium	Medium
Market Operation			
Increased cost, complexity, and vendor diversity of metering equipment to support market transactions	High	Medium	High
Increased cost of market transactions associated with data transfer, processing, and billing	High	High	Medium
Development of markets for power of different reliability levels	Medium	Medium	Medium
Development of markets for power of different quality levels	Medium	Medium	High

increased duration and frequency of power outages resulting from deregulation, indicate areas where measurement and standards may have the greatest impact on social welfare. Other areas, such as *limited transmission capacity to support increasing system demands resulting from deregulation*, which have a “high” significance for measurement and standards but a “medium” relative magnitude on system costs, are projected to have less overall impact on social welfare.

The variation column reflects the respondents' different opinions and uncertainties for both the relative magnitude associated with each issue/benefit/concern and the influence measurement and standards may have on enhancing the benefits or mitigating the problem. For example, most respondents agreed that measurement and standards would have a small but positive impact on the average cost of power generation—hence the variance is indicated as "low." In contrast, there was a significant difference of opinion among respondents about the impact measurement and standards may have on power quality to end users or on the development of markets for differentiated power quality—hence the variance for these impact area is "high."

For each economic impact area presented in Table 5-2, we discuss the relative magnitude of the issue/benefit/concern, the importance of measurement and standards, and the variance of responses below.

5.2.1 System Operations

Achieving Potential Efficiency Gains in Power Generation Resulting from Increased Competition

Potential Economic Impact (High). Power generation costs exceed $100 billion per year in the U.S. Deregulation and competitive wholesale markets offer the potential to lower the average cost of generation by increasing use of existing low-cost generators and opening the market to new generation technologies with improved energy efficiencies.

Role of Measurement and Standards (Medium). However, competitive markets can only work if the customer has a basis to compare the competitors. Comparisons cannot be made without measurement and standards. For example, standards for interconnection of new and different types of generation technologies and customer-owned systems (including total energy systems) to the grid are being developed, and they should help secure generation cost savings with deregulation. In addition, enhanced communications and information transfer systems will be needed to support market functions.

Variation in Responses (Low). Most respondents felt that there was little role for measurement and standards in increasing the engineering efficiency of generation. However, they did agree that measurement and standards were needed to support competition and that this would lead to modest reductions in the average cost of generation.

Adequate and Efficient Provision of Ancillary Services in a Deregulated Environment

Potential Economic Impact (Medium). The provision of ancillary services represents approximately $12 billion per year in the U.S. The fundamental change that occurs with deregulation is the reliance on competition and markets to provide the services that the regulated, vertically integrated electric utility used to provide. The regulator used to be able to hold the vertically integrated utility accountable for the (qualitatively judged) final result of reliable, affordable power. One of the goals of deregulation is that markets will be able to provide these unbundled services more efficiently.

Role of Measurement and Standards (Medium). A common theme associated with ancillary services is "you cannot buy or sell what you cannot measure." To unbundle ancillary services, each service, each service provider, and each service consumer must be measured. Standards to define the service and the service metrics are essential to help the markets develop, by providing appropriate guides to providers and useful service information to users. Measurement to quantify service characteristics and performance relative to these standards is essential.

Variation in Responses (Medium). Almost all respondents agreed that improvements need to be made in the industry's ability to measure ancillary services. However, there was less agreement about the potential efficiency gains that could be achieved as a result of unbundling ancillary services in general. Some respondents viewed measurement of ancillary services as more important to the distribution of costs and less important to supply efficiency or reliability.

Limited Transmission Capacity to Support Increasing System Demands Resulting from Deregulation

Potential Economic Impact (Medium). Transmission is increasingly difficult to build. Deregulation increases the pressure to obtain ever-increasing performance from scarce transmission resources.

Role of Measurement and Standards (High). Most transmission limitations are based on assumed environmental conditions, such as wind speed and temperature. Improved measurement can allow transmission lines to be operated much closer to actual design limits and to extract increased performance from the existing system. For example, FACTS can help relieve constrained interfaces through rapid reporting of power flows. However, the incremental gain in efficiency from FACTS is likely to diminish as their penetration grows because multiple devices in transmission regions tend to "compete" against each other when "rerouting" power flow.

Variation in Responses (High). Many respondents felt that limited transmission capacity was the most significant obstacle to achieving the potential benefits associated with deregulation. Because bottlenecks are likely to be created at the major interconnections and transfer points in the grid system, competition may be limited to regional markets. In addition, many respondents felt that straining the transmission system would affect power reliability, leading to more frequent and larger-scale outages.

Alternatively, other respondents viewed the transmission capacity issues as isolated, localized problems (primarily at major grid interconnection points). They believed these issues could be addressed through new technology and focused new transmission capacity additions. They agreed that measurement and standards would play an important role in resolving this issue; however, they felt that capacity was sufficient for most of the transmission system and that the enhancements needed to support deregulation would not be extremely costly (relative to other issues such as metering or communications needs).

Integrating DG into the System and Fully Using Its Resource Potential

Potential Economic Impact (Medium). Fully integrating distributed generation units into the power system will provide a variety of potential benefits. Distributed generation represents many small resources that inherently have reliability benefits when compared to few large resources, all other things being equal. In addition, distributed generation can be used to provide ancillary services, such as regulation and load following services, and will help alleviate transmission constraints.

Role of Measurement and Standards (High). Measurement and standards will lower the cost of interconnection and hence increase the availability of distributed generation for system support into smaller units. Large central generators can more easily afford expensive metering, communications, and control. They are also in less need of standards governing interconnection and performance requirements because they can financially support (and are in greater need of) individual studies and negotiations. Distributed generators cannot afford the same expenses on a unit-by-unit basis. They require cheaper metering and standard interconnections because there are so many more units to produce the same amount of power. Measurement and standards for communication protocols will also lower the cost of using distributed generation and improve performance, hence increasing reliability.

Variation in Responses (Medium). Most respondents agreed that the integration of smaller distributed generation units will yield efficient improvements. However, there was disagreement about the projected penetration of distributed generation. Beyond some penetration level, which was not defined by the respondents, distributed generation may create more power reliability and quality problems than it solves. There was also disagreement on whether distributed generation would help resolve or intensify problems associated with power reliability and power quality.

Increased Duration and Frequency of Power Outages Resulting from Deregulation

Potential Economic Impact (High). The greater stress placed on the power system by the increased levels of transactions brought about by deregulation will likely result in more frequent and longer power outages. The costs of power outages include both decreased productivity of labor and capital and increased expenditures on backup equipment. The annual economic impact of power outages is large because it affects all sectors of the economy.

Role of Measurement and Standards (High). Increased and improved measurement and standards will help alleviate the greater stress on transmission systems by supporting increased and more efficient use of existing transaction assets. Appropriate standards that define reliability services (e.g., outage frequency, duration, and magnitude by major source) and help to commercially motivate improved performance, coupled with measurement capability to verify that performance, should improve reliability.

Variation in Responses (Medium). Respondents generally agreed that the cost of power outages to industry is an important issue and that better measurement and standards would help improve power reliability. However, there was disagreement on whether deregulation would significantly increase power reliability problems and on how large an impact measurement and standards can have on mitigating these problems. For example, measurement and standards cannot eliminate outages caused by lightning and other "acts of God"; however, they may be able to mitigate the severity of such events.

Degradation in Power Quality Resulting from Deregulation

Potential Economic Impact (High). Power quality issues will become increasingly important with the increased use of sensitive electrical equipment. The cost of poor power quality includes equipment failures and lost productivity of labor and capital.

Role of Measurement and Standards (Medium). Increasing use of power electronics (electronic ballasts and adjustable speed drives) is increasing the injection of harmonics and flicker into the power system and creating problems for loads susceptible to power quality problems. Standards governing acceptable power performance and measurements to locate the source of problems are needed to maintain or increase power quality.

Variation in Responses (High). There was a broad range of opinion on the subject of power quality. On one hand, many respondents believed that power quality was an issue primarily confined to the customer's side of the meter and that deregulation of the electric power industry would have little effect on power quality issues. Also, power quality has many "dimensions" (e.g., surges, sags, harmonics, flicker), and defining appropriate standards for any one of these may vary with customer end uses and will raise many issues as to what an appropriate standard in each case will be. On the other hand, some respondents indicated that many power quality problems could be solved with improved measurement capabilities, which could then help move the development of standards forward, and that the potential benefits are large.

Inadequate Diagnostic Tools Capable of Monitoring System Conditions and Identifying Problems

Potential Economic Impact (High). Deregulation is expanding the geographic range of transactions. FERC is encouraging deregulation and encouraging the formation of RTOs to integrate transmission system operations over large geographic areas. Reliable operation of the integrated power system over these large geographic areas requires greater observability for the system operators. Increasingly more measurements must be coordinated.

Role of Measurement and Standards (Medium). Better tools are required to convert raw data into meaningful information. System operators in adjacent regions must be able to exchange data in real time to construct a coherent picture of the entire power system. Tools that can quickly analyze data on dynamic system performance are needed to augment existing tools that are used to analyze steady-state performance. Measurement and standards for communication can increase the speed and decrease errors of data exchange. In addition, measurement and standards can increase interoperability of different systems and lower costs associated with translation programs.

Variation in Responses (Medium). Almost all respondents indicated that improved diagnostic tools to monitor system conditions were needed and that measurement and standards could play an important role in developing these tools. However, there was concern regarding the cost-effectiveness of widespread implementation of advanced monitoring systems. Several respondents believed that the cost of such systems would limit their implementation and, hence, their impact in the foreseeable future.

5.2.2 Market Operations

Increased Cost of Metering Equipment to Support Market Transactions

Potential Economic Impact (High). Approximately 1 percent of electric power industry expenditures are related to purchasing, installing, and maintaining metering equipment. Deregulation will greatly increase these expenditures for both generators and loads as the need for real-time metering increases.

However, increased metering will generate benefits beyond simply supporting market transactions. Reliability and commerce are both enhanced when markets are opened to the real-time participation of more numerous and smaller resources. For example, on the supply side, fundamentally it is better to spread contingency reserves over numerous resources rather than to rely on a single large generator. This is because there is always a danger that the single generator will fail to respond when needed. Similarly, the amount of contingency reserves that a utility must provide depends on the size of the largest single contingency, usually the size of the largest single generator. More numerous but smaller generators result in increased reliability and reduced reserve requirements. In addition, the statistical behavior of a larger group is easier to predict.

On the load side, increased metering will enable the system to leverage the benefits of variations in customer demand elasticity. The benefits from enabling the customer as a resource are potentially very large, and some respondents characterized them as "hard to overestimate." These benefits become magnified when the power system is under stress and generation resources are scarce.

Role of Measurement and Standards (High). Measurement and standards can help reduce the cost of metering and communications equipment for smaller resources. Metering costs must be reduced for society to obtain the reliability and commercial benefits that smaller resources offer. Fortunately, volume also increases, so mass production benefits may be able to be exploited once the "technical specifications" for market participation are known and customer confidence in marketplace offerings is enhanced by standards.

Variation in Responses (Medium). Most respondents agreed that standardizing functionality of metering and communications equipment will support mass production and increase competition and, hence, lower costs. However, most respondents indicated that metering costs would increase as improved measurement and standards broaden metering applications. And there was concern that the high cost of advanced metering capabilities would delay the benefits of deregulation.

Increased Cost of Market Transaction Associated with Data Transfer, Processing, and Billing

Potential Economic Impact (High). Approximately 2 percent of electric power industry expenditures are related to data transfer, processing, and billing. Communications and transaction requirements will increase greatly as many more small generators and loads move into real-time markets.

However, similar to the issues associated with metering costs, the economic benefits from this move to real-time response for all load (large and small) will be large because it lowers costs through active competitive markets and increases reliability since more resources can respond when the system is under stress.

Potential Economic Impact (High). Measurement and standards can help reduce market transaction costs by increasing interoperability of the multiple networks and systems needed to support market transactions in a deregulated environment. The number of market participants supplying raw data to the system and receiving processed information will increase dramatically with deregulation. Measurement and standards will be important for enabling the communications systems supplied by multiple vendors to retrieve, process, and distribute information within acceptable time intervals to multiple market players.

Variation in Responses (Medium). Most respondents thought that measurement and standards can help reduce transaction costs so that they do not impede the benefits to be achieved through deregulation. However, there was disagreement on the capabilities of existing systems. Some respondents thought that existing communications systems and protocols would be adequate with ongoing modifications. Other respondents thought that significant changes in communications protocols and system interfaces needed to be made to achieve the potential benefits from deregulation.

Development of Markets for Power of Different Reliability Levels

Potential Economic Impact (Medium). Different industries and customers within industries value power reliability differently. This heterogeneity of customers' preferences for power reliability can be viewed as an asset that can be exploited through the development of different product offerings (see Section 2). By offering different levels of power reliability to customers, the system can become more efficient by reducing reserve requirements and reducing transmission investments. In addition, in many instances it is more efficient for the system to "guarantee" different levels of reliability as opposed to customers self-providing reliability through individual investments in backup equipment (e.g., uninterruptible power supplies, emergency generators).

Role of Measurement and Standards (Medium). Measurement and standards will be important to ensure that reliability levels specified in contracts have been met. In addition, for customers that do not need the full reliability inherently offered by the power system, communication and monitoring capabilities will be needed when customers opt for lower reliability by "selling" load relief back to the system. For example, standards for verifying that curtailments have actually occurred will be required to support the increased reliance on more, and more diverse, curtailment contracts.

Variation in Responses (Medium). Different levels of "firm" power already exist in the wholesale market. Most respondents agreed that this trend would continue and measurement and standards could help expand differentiated reliability offerings into the retail markets. However, there was disagreement about the potential size of these markets and when it would become cost-effective to open these markets to smaller loads.

Development of Markets for Power of Different Quality Levels

Potential Economic Impact (Medium). As with the market for different levels of power reliably, potential system efficiency gains exist if customers value power quality differently. Because power quality costs to industry and expenditures on power conditioning equipment are large, the potential benefits from establishing markets for power of different quality levels may be significant. In addition, markets could address issues of individual customer's impact on system power quality, where customers "pay" for the problems (e.g., harmonics) they feed back into the system.

Role of Measurement and Standards (Medium). There is an increasing need to be able to detect power quality problems through measurements and to define acceptable performance through standards. Standards will be important to reduce power quality problems from sources at the generation level (e.g., with smaller, newer distributed generators), at the "wires" level (e.g., if appropriate power conditioning is not provided at key points in the system), and at the customer level (e.g., from electronic ballasts and adjustable speed drives). Standards can also help define and match users (or uses) who have different demands for power quality with providers (or sources) that supply different levels of power quality.

Variation in Responses (High). There was significant disagreement on whether markets for differentiated levels of power quality would emerge in the near future. Some respondents cited the high cost of providing different levels of power quality to customers on the same distribution system as a barrier to power quality markets. However, other respondents indicated there was a need for market incentives/penalties to encourage customers to address their internal power quality problems and not to feed harmonics back into the system. They believed measurement and standards were needed to support the development of efficient incentives.

5.3 ECONOMIC IMPACT ESTIMATES

This section presents a range of monetary benefits estimates that reflect the social welfare gains of measurement and standards in supporting deregulation of the electric power industry. We refer to these as economic impact estimates. The economic impact estimates presented in this section are based on common impact "themes" identified during interviews with industry experts. The empirical estimates provided below are intended to illustrate the magnitude of the potential benefits associated with measurement and standards. These impact estimates do not reflect projected cost savings developed from detailed engineering analysis or results from a statistically based survey. Instead, they should be considered "first cut" estimates that can be refined as deregulation progresses and as the evidence on impacts grows.

Economic impacts are evaluated relative to the performance gap resulting from "inadequate" measurement and standards. This is measured as a percent reduction in potential efficiency gain. These economic impact estimates are designed to capture changes in total social welfare. These changes in social welfare are not desegregated into changes in consumer or producer surplus or traced to changes in market prices.[3]

We used the following steps to develop the economic impact estimates associated with measurement and standards:

- Review the impact areas discussed in Section 5.2 and select a subset for the empirical analysis of measurement and standards.
- Develop impact cost metrics for each selected area based on professional literature, trade publications, and government publications.
- Use the scoping interviews and surveys with industry experts to investigate the significance of measurement and standards associated with each impact cost metric. From this information, develop a percentage change impact range for each impact cost metric.
- Estimate economic impact range estimates by multiplying the impact cost metric by the percentage change ranges.

Figure 5-1 illustrates how the impact cost metrics and percent change estimates were used to estimate economic impacts. The lower curve in Figure 5-1 represents the potential productivity gain (reduction in the average price of generation) associated with deregulation with adequate measurement and standards. The upper curve reflects the gain that may be achieved without adequate measurement and standards. The difference between the two curves is the productivity "gap" between potential and actual average price decreases that is not realized as a result of inadequate measurement and standards. Information on the size of the gap

[3]Respondents had very different opinions regarding which sectors of the economy would benefit most from deregulation. Investigating the distribution of benefits was beyond the scope of this study.

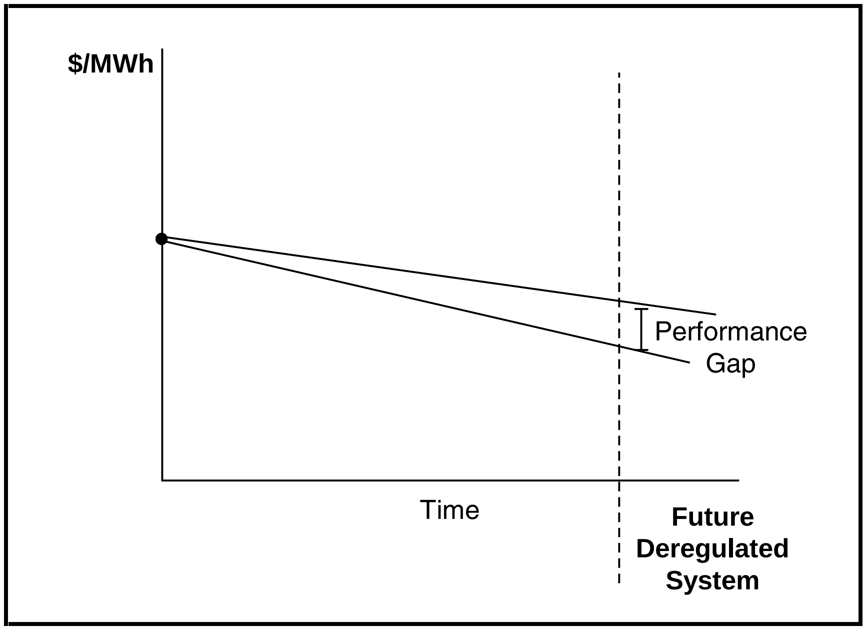


Figure 5-1. Potential Performance Gap Associated with Inadequate Measurement and Standards
The potential performance gap is the difference between the projected and actual average cost of power resulting from inadequate measurement and standards. The performance gap is expressed as a percentage change in per-unit power generation costs in this example.

was obtained through interviews with industry experts and is expressed as the percentage gap to simplify data collection.

The percentage gap is multiplied by an impact cost metric to obtain the economic impact:

Economic Impact = Percentage Gap • Impact Cost Metric

Economic Impact = % Change in Average Cost of Power Generation • Annual U.S. Expenditures on Power Generation

Note, we are not estimating the economic impact of the potential gains in economic performance of deregulation. The economic impact estimates presented in this study are the *reductions* in the economic performance gains resulting from inadequate measurement and standards.

Section 5.3.1 discusses the development of the impact cost metrics, and Section 5.3.2 presents the percentage change ranges along with the economic impact range estimates.

5.3.1 Impact Cost Metrics

A key step in estimating economic impacts is to identify and quantify impact cost metrics that would provide a reference value from which the impact of measurement and standards can be measured. The impact costs metrics are the building blocks used to estimate the economic impacts. For example, if measurement and standards increase the capacity utilization of the transmission system and reduce the need for new transmission capacity, we need to know the cost of building additional transmission capacity. Similarly, if measurement and standards can reduce the frequency and duration of outages, then we need to know the annual cost of outages to end users to estimate the economic impact of measurement and standards on outage costs.

The advantage of defining impact cost metrics independent of the role of measurement and standards is that the impact cost metrics have less uncertainty compared to the question of "what is the significance of measurement and standards." By first calculating independent impact cost metrics, we can then investigate a range of economic impacts associated with measurement and standards (reflecting potentially very different views of the world) based on a common reference point.

Impact cost metrics were developed for seven impact areas.

We developed impact cost metrics for seven of the impact areas presented in Table 5-2. The remaining four impact areas listed in Table 5-2 were not explicitly quantified because their impacts are either included in other impact categories or their market factors were too uncertain to quantify. For example, the benefits of measurement and standards to support distributed generation are incorporated into the reduced cost of ancillary services and the reduced demand for transmission resources. In addition, distributed generation may also help alleviate the frequency and severity of outages, and this would be reflected in the economic impacts associated with measurement and standards reducing outage costs. In general, we found that the impact of distributed generation was too difficult for interviewees to untangle from the other categories, such as ancillary service or transmission impact.

Similarly, the impact of measurement and standards on diagnostic tools is indirectly reflected in the benefit associated with operating the transmission system and in improved power reliability and power quality for end users.

The impact areas for differentiated levels of power reliability and power quality were also not included in the empirical analysis. For these areas, it was difficult to quantify the potential benefits, and there was significant disagreement about the future evolution of these markets and the role measurement and standards may play. Respondents were reluctant to offer estimates of these impacts because of the historically high levels of power reliability and quality prevalent in U.S. electricity markets.

Table 5-3 describes the cost metrics included in the empirical analysis and identifies the information sources used to develop annualized expenditures or costs. Appendix E contains a detailed description of the estimation procedures and assumptions that we used to develop each cost metric estimate.

The cost metrics reflect U.S. impacts. When information was only available for North America, costs were scaled by the U.S.'s share of electricity consumption (the U.S. accounts for approximately 84 percent of electricity consumed in North America). In addition, the impact cost metrics focus on the "end results" and estimate the impact at the point it enters the supply chain. Specific modeling of the physical and behavioral relationships between these categories is beyond the scope of this study.

5.3.2 Economic Impact Estimates

We calculated economic impact estimates based on the impact cost metrics described above and percentage change range estimates developed through interviews and surveys with industry experts.

Most industry experts had difficulty quantifying the incremental impact associated with measurement and standards because these impacts needed to be measured relative to an unknown baseline (i.e., the future course of deregulation).[4] Whereas respondents

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[4]In addition, quantifying the impact is also difficult because the basic structure of how we conceptualize the industry relies on metering individual consumption. For example, the whole structure of the restructured industry is based on unbundling and, therefore, measuring individual provision and consumption. It is difficult to conceive of a deregulated world without adequate measurement and standards.

Table 5-3. Impact Areas Affected by Measurement and Standards
The cost metrics form the "building blocks" for estimating economic impacts associated with measurement and standards.

Impact Area	Cost Metric	Sources
System Operations		
1) Achieving potential efficiency gains in power generation resulting from increased competition	Annual U.S. expenditures on power generation	Energy Information Administration. 1998b. *Electric Power Annual.* Volume 2. Washington, DC: U.S. Department of Energy.
2) Adequate and efficient provision of ancillary services in a deregulated environment	Annual U.S. expenditures on ancillary services	Hirst, Eric and Brendan Kirby. 1998. "Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services." Prepared for the National Regulatory Research Institute, Columbus, OH.
3) Limited transmission capacity to support increasing system demands resulting from deregulation	Avoided cost of new transmission resources: ➤ building new corridors ➤ restraining existing corridors	Fuldner, Arthur. 1996. *Upgrading Transmission Capacity for Wholesale Electric Trade*. Washington, DC: Energy Information Administration. Edison Electric Institute. 1998. *Statistical Yearbook of the Electric Utility Industry 1997*. Washington, DC: Edison Electric Institute.
4) Increased duration and frequency of power outages resulting from deregulation	Annual power outage costs to U.S. industries, and Expenditures on backup equipment to support reliability	Hoffman, Steve. 1996. "Enhancing Power Grid Reliability." *EPRI Journal* 21(6):6-16. Power Quality Assurance. 1999. "The Top 50 Equipment Suppliers and Service Providers." <http://www.powerquality.com/art0055/art1.html>. As obtained on October, 13 1999.
5) Degradation of power quality resulting from deregulation	Expenditures on protective equipment to mitigate power quality problems[a]	Power Quality Assurance. 1999. "The Top 50 Equipment Suppliers and Service Providers." <http://www.powerquality.com/art0055/art1.html>. As obtained on October, 13 1999.
Market Operations		
6) Increased cost of market transactions associated with data transfer, processing, and billing	Annual U.S. industry expenditures on contract writing, legal disputes, and bill reconciliation	Energy Information Administration. 1997. *Financial Statistics of Major Investor Owned Utilities, 1996*. Washington, DC: U.S. Department of Energy.
7) Increased cost, complexity, and vendor diversity of metering equipment to support market transactions	Annualized cost of metering equipment Annualized cost of operating metering systems (installation, calibration, service calls, wireless communications equipment)	Electrical World. 1998. "Meter Market Measures." <http://www.gepin.com/tombew/08009813.htm>. As obtained on November 22, 1999. Energy Information Administration. 1997. *Financial Statistics of Major Investor Owned Utilities, 1996*. Washington, DC: U.S. Department of Energy.

[a]Note: Information was not available on annual power quality costs to U.S. industries.

indicated that measurement and standards would be important regardless of the eventual course of deregulation, asking respondents to quantify the impact of measurement and standards in the presence of such great future uncertainty made it difficult to elicit comparable impact metrics that could be aggregated using statistical methods. As a result, our approach for assessing the range of the percentage change impact associated with measurement and standards was to

- review each survey response separately,
- assess the baseline from which each respondent was developing his impact estimates,
- identify common measurement and standards impact themes, and
- develop ranges of measurement and standards impact estimates based on assimilating input from all responses.

Based on this approach, we developed impact metrics that were used to estimate ranges of potential economic impacts associated with measurement and standards. We want to emphasize that the economic impact estimates presented in this section reflect the authors' interpretation of information collected through a series of telephone interviews and survey questionnaires and are not the result of a statistically based survey.

Most industry experts felt that measurement and standards can have the greatest percentage change (or relative) impact on the cost of providing ancillary services, the level of power reliability, and power quality experienced by end users.

Table 5-4 presents the range of percentage change impacts for each cost metric category that was developed based on discussions with industry experts. The economic impact estimates reflect the potential efficiency gains (gains associated with deregulation) that are not realized as a result of inadequate measurement and standards. Upper and lower bounds of the performance "gap" are estimated in terms of the percentage change relative to the cost metric. For example, for Impact Area 2, respondents indicated that deregulation could significantly reduce the average cost of providing ancillary services. However, the eventual deregulated cost of ancillary services will be 8 to 12 percent higher without adequate measurement and standards. The economic impact is then calculated by multiplying the percentage performance gap by the annual expenditures on ancillary services (the impact cost metric).

Table 5-4. Economic Impact of Measurement and Standards
The economic impact estimates reflect the potential performance gains (gains associated with deregulation) that are not realized as a result of inadequate measurement and standards. An upper and lower bounds of the performance "gap" are estimated in terms of the percentage change relative to the cost metric. For example, for Impact Area 2, respondents indicated that deregulation could significantly reduce the average cost of providing ancillary services. However, the eventual deregulated cost of ancillary services will be 8 to 12 percent higher without adequate measurement and standards. The economic impact is then calculated by multiplying the percentage performance gap by the annual expenditures on ancillary services (the impact cost metric).

Impact Area	Cost Metric[a] ($ millions)	Percentage Reduction in Potential Efficiency Gain		Economic Impact[b] ($ millions)	
		Lower	Upper	Lower	Upper
System Operations					
1) Achieving potential efficiency gains in power generation resulting from increased competition	100,000	0.5%	1.5%	500	1,500
2) Adequate and efficient provision of ancillary services in a deregulated environment	12,000	8%	12%	960	1,440
3) Limited transmission capacity to support increasing system demands resulting from deregulation	7,700	0%	6%	0	462
4) Increased duration and frequency of power outages resulting from deregulation	30,000	5%	9%	1,500	2,700
5) Degradation in power quality resulting from deregulation	4,300	6%	12%	258	516
Market Operations					
6) Increased cost of market transactions associated with data transfer, processing, and billing	800	1%	5%	8	40
7) Increased cost, complexity, and vendor diversity of metering equipment to support market transactions	2,200	–4%	–6%	–88	–132
Total				3,138	6,526

[a]All costs and economic impacts are presented in 1999 dollars.

[b]The economic impacts are presented as benefits of measurement and standards. Thus, a positive percentage change typically reflects a decrease in expenditures (such as for power generation or new transmission capacity) or a decreased burden on end users associated with a "bad" outcome (such as power outages).

Most industry experts felt that measurement and standards can have the greatest percentage change (or relative) impact on the cost of providing ancillary services, the level of power reliability, and power quality experienced by end users.

Measurement and standards was thought to have a smaller relative impact on the cost of generation, ranging from 1 to 2 percent. However, because generation costs represent over $100 billion annually, this category still represents a significant economic impact.

Measurement and standards' impact on transmission system costs had the largest range, reflecting varying opinions on the net economic impact. Many interviewees cited increased capacity utilization of the transmission system and avoided costs of new transmission capacity as large benefits resulting from measurement and standards. However, other interviewees felt that these benefits would be offset by increased monitoring and diagnostic costs that would accompany increased measurement capabilities. As a result, this category ranges from 0 to 6 percent change.

It should be noted that many of the benefits of measurement and standards as applied to the transmission system will be captured in reduced outage costs and power quality costs to end users. Several respondents may have allocated the costs of measurement and standards to Impact Area 2 in Table 5-4 and implicitly included the associated benefits in Impact Areas 4 and 5.

The sum of the annual economic impacts quantified as part of this study ranges from $3.1 to $6.5 billion.

As shown in the last two columns of Table 5-4, the sum of the annual economic impacts quantified as part of this study ranges from $3.1 to $6.5 billion. Measurement and standards' impact on power reliability is the largest impact category, representing 35 percent of the upper-bound estimate. Power quality issues for end users, average generation costs, and ancillary service costs each account for approximately 20 percent of the upper-bound estimate.

The percentage change in equipment costs ranges from –4 to –6 percent. The impact is negative because respondents indicated that metering equipment costs throughout the system would increase as a result of more refined and more frequent measurements at more locations. Thus, this appears as a negative economic impact in Table 5-4. However, the respondents indicated that benefits would be associated with these increased metering activities, and they are captured in the other categories in Table 5-4, such as decreased ancillary service costs. Also, enhanced metering may generate additional benefits through support of markets for differentiated power reliability and power quality (not included in Table 5-4).

As noted previously, these estimates are illustrative "first cut" estimates of economic impacts based on a survey of a limited number of electric industry experts early in the industry deregulation process. Although the results are not highly precise, the pattern of results within the system and market operations categories are plausible and provide early guidance to measurement and standards development initiatives and investments. Examples of groups that are involved in the measurement and standards development process are provided in Section 4.

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Appendix A: Existing Activities and Emerging Participants in the Electric Power Supply Chain

This appendix provides background on existing activities and emerging participants in the electric power supply chain. Because the restructuring plans and time tables are made at the state level, the issues of asset ownership and control throughout the present supply chain in the electric power industry vary from state to state. However, the activities conducted throughout the supply chain are generally the same.[1]

Section A.1 presents a brief history of the development of the electric supply industry. Figure A-1 provides an overview of the present state of the electric power supply chain, highlighting a combination of activities and service providers. The activities/members of the electric power supply chain are typically grouped into generation, transmission, and distribution. These three segments are described in Sections A.2 through A.4. Equipment manufacturers supply all three segments and are described in Section A.5.

A.1 EVOLUTION OF THE ELECTRIC POWER INDUSTRY

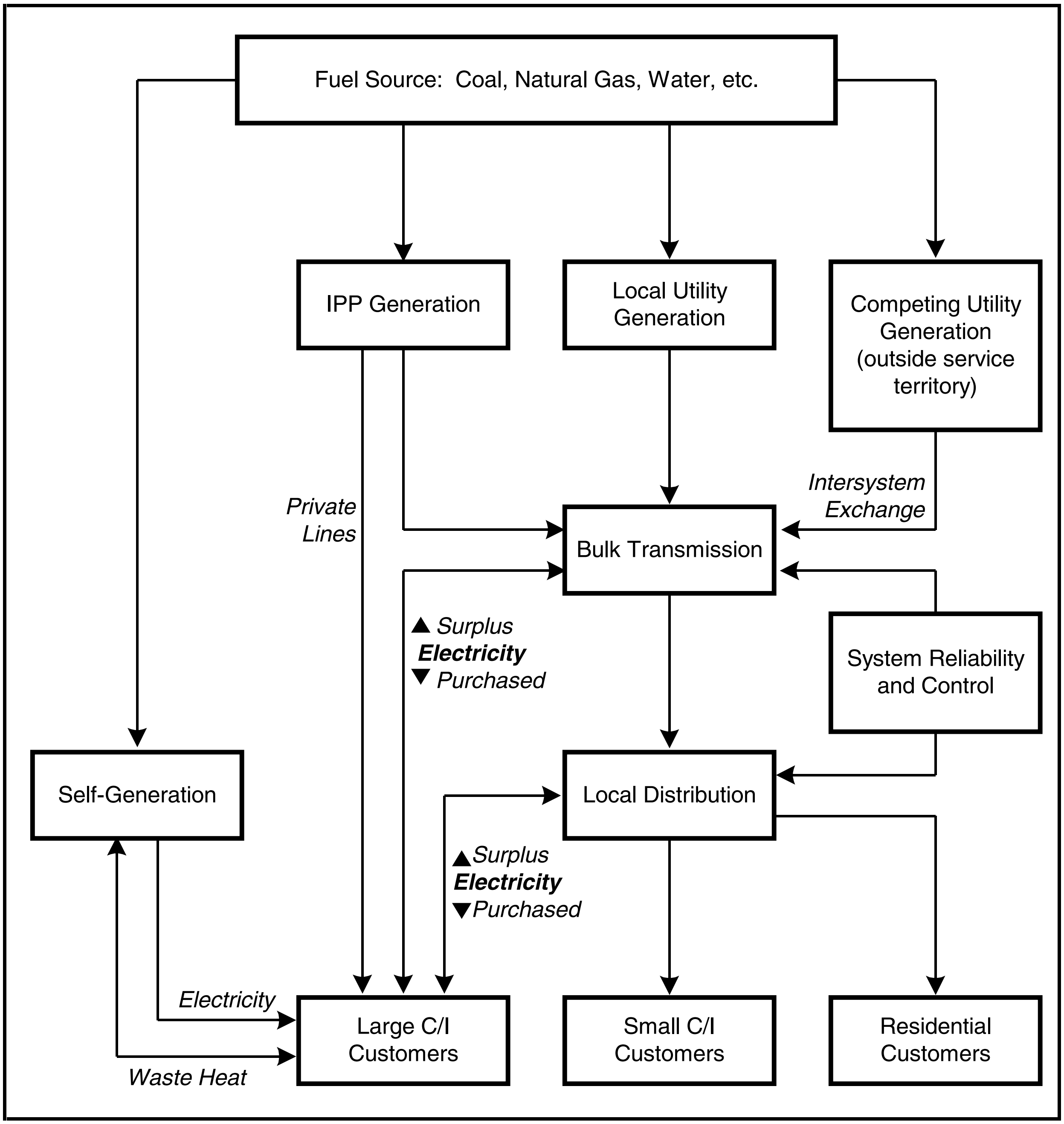
The electric utility industry began as isolated local service systems with the first electric companies evolving in densely populated metropolitan areas like New York and Chicago. Prior to World War I, rural electrification was a piecemeal process. Only small, isolated systems existed, typically serving a single town. The first high-voltage transmission network was built in the Chicago area in 1911 (the Lake County experiment). This new network connected the smaller systems surrounding Chicago and resulted in substantial production economies, lower customer prices, and increased company profits.

In light of the success of the Lake County experiment, the 1910s and 1920s saw increased consolidation and rapid growth in electricity usage. During this period, efficiency gains and demand growth provided the financing for system expansions. Even though

[1]Of course, asset ownership and control are at the heart of deregulation and are an important factor driving the need for measurement and standard technologies, and these issues are discussed in detail in Section 3.

the capacity costs (fixed costs per peak kW demanded) were typically twice as large with the consolidated/interconnected supply

Figure A-1. Electric Utility Industry



systems, the fixed costs per unit of energy production (kWh) were comparable to those of the old single-city system. This was the case because of load factor improvements, which resulted from aggregating customer demand.

Whereas the average fixed cost per customer was relatively unchanged as a result of the move from single-city to consolidated supply systems, large savings were realized from decreases in operating costs. In particular, fuel costs per kWh decreased 70 percent because of the improved combustion efficiency of larger plants and lower fuel prices for purchases of large quantities. In addition, operating and maintenance costs decreased 85 percent, primarily as a result of decreased labor intensity.

During the 1920s, only a small part of the efficiency gains were passed on to customers, in the form of lower prices. Producers retained the bulk of the productivity increases as profits. These profits provided the internal capital to finance system expansions and to buy out smaller suppliers. Industry expansion and consolidation led to the development of large utility holding companies whose assets were shares of common stock in many different operating utilities.

The speculative fever of the 1920s led to holding companies' purchasing one another, creating financial pyramids based on inflated estimates of company assets. With the stock market crash in 1929, shareholders who had realized both real economic profits and speculative gains lost large amounts of money. The financial collapse of the utility holding companies led to new levels of utility regulation.

From the 1930s through the 1960s, the regulated mandate of electric utilities was basically unchanged: to provide safe, adequate, and reliable service to all users of electricity. The majority of the state and federal laws regulating utilities in place during this era had been written shortly after the Depression. The laws were primarily designed to prevent "ruinous competition" through costly duplication of utility functions and to protect customers against exploitation from a monopoly supplier.

During this period, most utilities were vertically integrated, controlling everything from generation to distribution. Economies of scale in generation and the inefficiency of duplicating transmission and distribution systems made the electric utility industry a textbook example of a natural monopoly. Electricity was viewed as a homogeneous good from which there were no product unbundling opportunities or unique product offerings on which competition could get a foothold. In addition, the industry was extremely capital-intensive, providing a sizable barrier to entry even if the monopoly status of the utilities had not been protected.

From the 1930s to the 1960s, the electric industry experienced almost continuous growth in demand. In addition, there was a steady stream of technological innovations in generation, transmission, and distribution operations. The increased economies of scale, technological advances, and fast demand growth led to steadily declining unit costs. However, in an environment of decreasing unit costs, there were few rate cases and almost no pressure from customers to change the system. This period is often referred to as the golden era for the electric utility industry.

A.2 GENERATION

The transmission and distribution of electricity are being separated from the business of generating electricity, and a new competitive market in electricity generation is evolving. As power generators prepare for the competitive market, the share of electricity generation attributed to nonutilities and utilities is shifting.

More than 7,000 electricity suppliers currently operate in the U.S. market. As shown in Table A-1, approximately 42 percent of suppliers are utilities and 58 percent are nonutilities. Utilities include investor-owned, cooperatives, and municipal systems. Of the approximately 3,100 utilities operating in the U.S., only approximately 700 generate electric power. The majority of utilities distribute electricity that they have purchased from power generators via their own distribution systems.

Utility and nonutility generators produced a total of 3,369 billion kWh in 1995. Although utilities generate the vast majority of electricity produced in the U.S., nonutility generators are quickly eroding utilities' shares of the market. Nonutility generators include private entities that generate power for their own use or to sell to utilities or other end users. Between 1985 and 1995, nonutility generation increased from 98 billion kWh (3.8 percent of total generation) to 374 billion kWh (11.1 percent). Figure A-2 illustrates this shift in the share of utility and nonutility generation.

Table A-1. Number of Electricity Suppliers in 1999

Electricity Suppliers	Number
Utilities	3,124
Investor-Owned Utilities	222
Cooperatives	875
Municipal Systems	1,885
Public Power Districts	73
State Projects	55
Federal Agencies	14
Nonutilities	4,247
Nonutilities (excluding EWGs)	4,103
Exempt Wholesale Generators	144
Total	7,371

Source: Edison Electric Institute. 1999a. "The Number of Electricity Suppliers in Today's Market." <http://www.eei.org/issues/comp_reg/3electri.htm>. As obtained on August 11, 1999.

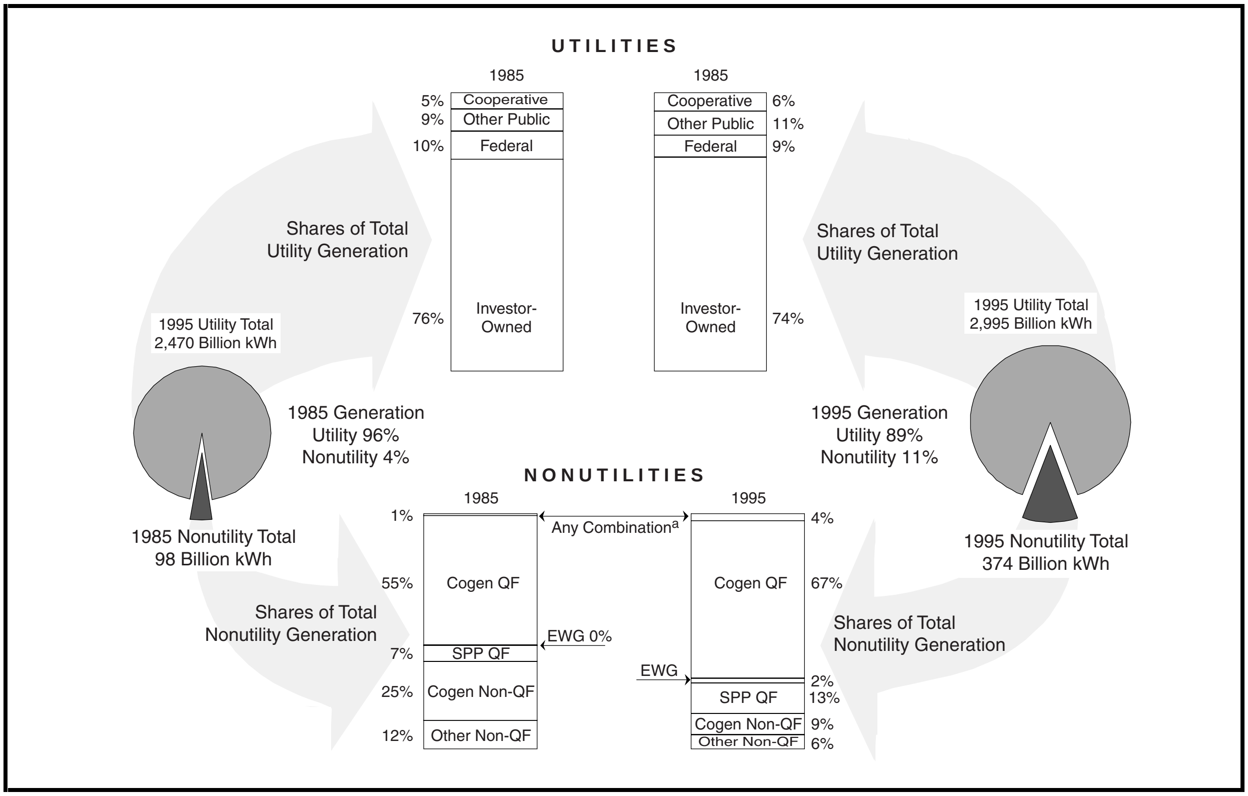
Utilities

There are four categories of utilities: IOUs, federal utilities, publicly owned utilities, and cooperative utilities. Of the four, only IOUs always generate electricity.

IOUs are increasingly selling off generation assets to nonutilities or converting those assets into nonutilities (Haltmaier, 1998). To prepare for the competitive market, IOUs have been lowering their operating costs, merging, and diversifying into nonutility business.

In 1995, utilities generated 89 percent of electricity, a decrease from 96 percent in 1985. IOUs generate the majority of the electricity produced in the U.S. IOUs are either individual corporations or a holding company, in which a parent company operates one or more utilities integrated with one another. IOUs account for approximately three-quarters of utility generation, a percentage that held constant between 1985 and 1995.

Figure A-2. Utility and Nonutility Generation and Shares by Class, 1985 and 1995



[a]Includes facilities classified in more than one of the following FERC designated categories: cogenerator QF, small power producer QF, or exempt wholesale generator.
Cogen = Cogenerator.
EWG = Exempt wholesale generator.
Other Non-QF = Nocogenerator Non-QF.
QF = Qualifying facility.
SPP = Small power producer.

Note: Sum of components may not equal total due to independent rounding. Classes for nonutility generation are determined by the class of each generating unit.

Sources: **Utility data:** Energy Information Administration (EIA). 1995a. "Annual Electric Utility Report." Form EIA-861. Washington, DC: U.S. Department of Energy; and Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volume I. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy; Table 8 (and previous issues); **1985 nonutility data:** Shares of generation estimated by EIA; total generation from Edison Electric Institute (EEI). 1992. *Statistical Yearbook of the Electric Utility Industry 1991*. November. Washington, DC; **1995 nonutility data:** Energy Information Administration (EIA). 1995b. "Annual Nonutility Power Producer Report" Form EIA-867. Washington, DC: U.S. Department of Energy.

Utilities owned by the federal government accounted for about one-tenth of generation in both 1985 and 1995. The federal government operated a small number of large utilities in 1995 that supplied power to large industrial consumers or federal installations. The Tennessee Valley Authority is an example of a federal utility. Most of the remaining energy is sold on the wholesale market to IOUs and cooperatives (EIA, 1996a). Very little energy is sold to retail customers.

Many states, municipalities, and other government organizations also own and operate utilities, although the majority do not generate electricity. Those that do generate electricity operate capacity to supply some or all of their customers' needs. They tend to be small, localized outfits and can be found in 47 states. These publicly owned utilities accounted for about one-tenth of utility generation in 1985 and 1995. In a deregulated market, these generators may be in direct competition with other utilities to service their market.

Rural electric cooperatives are the fourth category of utilities. They are formed and owned by groups of residents in rural areas to supply power to those areas. Cooperatives generally purchase from other utilities the energy that they sell to customers, but some generate their own power. Cooperatives only produced 5 percent of utility generation in 1985 and only 6 percent in 1995.

Nonutilities

Nonutilities are private entities that generate power for their own use or to sell to utilities or other establishments. Nonutilities are usually operated at mines and manufacturing facilities, such as chemical plants and paper mills, or are operated by electric and gas service companies (EIA, 1998a). More than 4,200 nonutilities operate in the U.S.

Between 1985 and 1995, nonutility generators increased their share of electricity generation from 4 percent to 11 percent (see Figure A-2). In 1978, the Public Utilities Regulatory Policies Act (PURPA) stipulated that electric utilities must interconnect with and purchase capacity and energy offered by any qualifying nonutility. In 1996, FERC issued Orders 888 and 889 that opened transmission access to nonutilities and required utilities to share information about available transmission capacity. These moves established wholesale competition, spurring nonutilities to increase generation and firms to invest in nonutility generation.

Nonutilities are frequently categorized by their FERC classification and the type of technology they employ. There are three categories of nonutilities: cogenerators, small power producers (SPPs), and exempt wholesale generators (EWGs).

Cogenerators are nonutilities that sequentially or simultaneously produce electricity and another form of energy (such as heat or steam) using the same fuel source. At cogeneration facilities, steam is used to drive a turbine to generate electricity. The waste heat and steam from driving the turbine is then used as an input in an industrial or commercial process. For a cogenerator to qualify or interconnect with utilities, it must meet certain ownership, operating, and efficiency criteria specified by FERC. In 1985, about 55 percent of nonutility generation was produced by cogenerators that qualified or met FERC's specifications and sold power to utilities. By 1995, the percentage increased to 67 percent as the push for deregulation gathered momentum. At the same time, the percentage that was produced by nonqualifying cogenerators decreased from 25 percent to 9 percent.

SPPs generate power using renewable resources, such as biomass, solar energy, wind, or water. As with cogenerators, SPPs must fulfill a series of FERC requirements to interconnect with utilities. PURPA revisions enabled nonutility renewable electricity to grow significantly, and SPPs have responded by improving technologies, decreasing costs, and increasing efficiency and reliability (EIA, 1998a). Between 1985 and 1995, the percentage of SPP nonutility generation nearly doubled to 13 percent.

EWGs produce electricity for the wholesale market. Also known as independent power producers, EWGs generate for large bulk customers, such as large industrial and commercial facilities and utilities. They do not operate any transmission or distribution facilities but pay tariffs to use facilities owned and operated by utilities. Unlike with qualifying cogenerators and SPPs, utilities are not required to purchase energy produced by EWGs, but they may do so at market-based prices. EWGs did not exist until the Energy Policy Act created them in 1992, and by 1995 they generated about 2 percent of nonutility electricity.

In 1995, about 4 percent of nonutility generation was produced by facilities that were classified as any combination of cogenerator, SPP, and EWG. An additional 6 percent was produced by facilities that generate electricity for their own consumption.

A.3 TRANSMISSION

Whereas the market for electricity generation is moving toward a competitive structure, the transmission of electricity is currently (and will likely remain) a regulated, monopoly operation. In areas where power markets are developing, generators pay tariffs to distribute their electricity over established lines owned and maintained by independent organizations. Independent system operators (ISOs) will most likely coordinate transmission operations and generation dispatch over the bulk power system.

The bulk power transmission system consists of three large regional networks, which also encompass smaller groups. The three networks are geographically defined: the Eastern Interconnect in the eastern two-thirds of the nation, the Western Interconnect in the western portion, and the Texas Interconnect, which encompasses the majority of Texas. The western and eastern networks are each fully integrated with Canada. The western is also integrated with Mexico. Within each network, the electricity producers are connected by extra high-voltage connections that allow them to transfer electrical energy from one part of the network to the other. The networks themselves are only loosely connected to one another; therefore, transferring electricity between one another is difficult.

RTOs are entrusted with coordinating electricity transmission and assuring reliability of the system. The RTO's operations and the tracking, monitoring, and information activities to support the RTO are common costs. All of the users of the system are required to contribute to support these activities that ensure efficient system operation and reliability. Although California is the only state that has completed the deregulatory process, there are four RTOs in operation: the California RTO, RTO New England, the Pennsylvania-New Jersey-Maryland RTO, and the Electric Reliability Council of Texas-Texas RTO. Seven others are planned.

The bulk power system makes it possible for electric power producers to engage in wholesale trade. In 1995, utilities sold 1,283 billion kWh to other utilities. The amount of energy sold by nonutilities has increased dramatically from 40 billion kWh in 1986 to 222 billion kWh in 1995, an average annual increase of 21 percent (EIA, 1996a). Distribution utilities and large industrial and commercial customers also have the option of purchasing electricity in bulk at market prices from their local utility, a nonutility, or another utility. The process of transmitting electricity between suppliers via a third party is known as wholesale wheeling.

The wholesale trade for electricity is increasingly handled by power marketers (brokers). Power marketers act as independent middlemen that buy and sell wholesale electricity at market prices (EEI, 1999b). Customers include large commercial and industrial facilities in addition to utilities. Power marketers emerged in response to increased competition. Brokers do not own generation facilities, transmissions systems, or distribution assets, but they may be affiliated with a holding company that operates generation facilities. Currently, 570 power marketers operate in the U.S. The amount of power sold by marketers increased from 3 million MWh to 2.3 billion MWh between 1995 and 1998. This is the equivalent of going from powering 1 million homes to powering 240 million homes (EEI, 1999b). Table A-2 lists the top ten power marketers by sales for the first quarter of 1999.

Table A-2. Top Power Marketing Companies, First Quarter 1999

Company	Total MWh Sold
Enron Power Marketing, Inc.	78,002,931
Southern Company Energy Marketing, L.P.	38,367,107
Aquila Power Corp.	29,083,612
PG&E Energy Trading-Power, L.P.	28,463,487
Duke Energy Trading & Marketing, L.L.C.	22,276,608
LG&E Energy Marketing, Inc.	15,468,749
Entergy Power Marketing Corp.	12,670,520
PacifiCorp Power Marketing, Inc.	11,800,263
Tractebel Energy Marketing, Inc.	10,041,039
NorAm Energy Services, Inc.	9,817,306

Source: Resource Data International. 1999. "PMA Online Top 25 Power Marketer Rankings." *Power Marketers Online Magazine*. <http://www.powermarketers.com/top25a.htm.> As obtained on August 11, 1999.

A.4 DISTRIBUTION

The local distribution system for electricity is expected to remain a regulated monopoly operation. But power producers will soon be able to compete for retail customers, by paying tariffs to entities that distribute the power. Utilities may designate an RTO to operate the distribution system or continue to operate it themselves. If the utility operates its own system, it is required by law to charge the same tariff to other power producers that it charges producers within its own corporate umbrella. The sale of electricity by a utility or other supplier to a customer in another utility's retail service territory is known as retail wheeling.

Supporters of retail wheeling claim that it will help lower the average price paid for electricity. The states with the highest average prices for electricity are expected to be the first to permit retail wheeling; wholesale wheeling is already permitted nationwide. In 1996, California, New England, and the Mid-Atlantic states had the highest average prices for electricity, paying 3 cents or more per kilowatt-hour than the national average of 6.9 cents (EIA, 1998a). Open access to the electricity supply, coupled with a proliferation of electricity suppliers, should combine to create falling electricity prices and increasing usage. By 2002, the nationwide average price for electricity is projected be 11 percent lower than in 1995, an average annual decline of roughly 2 percent (Haltmaier, 1998).

The explosion in computer and other information technology usage in the commercial sector is expected to offset energy-efficiency gains in the residential and industrial sectors and lead to a net increase in the demand for electricity. Retail wheeling has the potential to allow customers to lower their costs per kilowatt-hour by purchasing electricity from suppliers that best fit their usage profiles. Large commercial and industrial customers engaged in self-generation or cogeneration will also be able to sell surplus electricity in the wholesale market.

A.5 METERING AND DATA COMMUNICATIONS

Metering and data communications activities are an integral part of the electric power industry supply chain. Advances in metering and data communications technologies have been essential in supporting emerging electric power markets. Hourly meter readings, communicated daily, are currently considered the ideal data to support the transactions associated with a restructured electric market. This information is primarily needed to support transactions between wholesale providers and the retail sellers of energy, and to a lesser extent this information is needed to support transactions between customers and their retail suppliers (NARUC, 1998).

Hourly metering is currently in place at most large commercial and industrial facilities. However, the costs of hourly metering equipment and the communication logistics have limited the penetration of hourly metering equipment into the small commercial and industrial and residential sectors. For these smaller energy users, profiling is typically used to develop proxies for actual hourly metering.

Profiling estimates an end user's hourly consumption by assuming that the end user's monthly energy use follows a pattern that is similar to others in the end-user's class. Hourly usage profiling is then estimated based on the class' usage pattern and the end-user's monthly meter reading. The disadvantage of profiling is that it provides no incentive or mechanism for end users to respond to short-term market forces. In addition, profiling introduces inaccuracies by "averaging" end-users' usage, which leads to issues of equity and fairness in billing.

In addition to the cost of installing the metering equipment, communications and processing of metering data present barriers to the penetration of hourly meter reading for smaller end users. Manual methods for meter reading are in the process of being replaced by automated meter reading (ARM) systems. However, the technologies to support ARM are still evolving.

The technology for automated communications of meter data is generally grouped in to two categories:

- ➤ dedicated ARM networks and
- ➤ multipurpose networks that are "transparent" to the function they are supporting (NARUC, 1998).

Dedicated ARM networks have the advantage that the majority of electric customers can be equipped to fully benefit from open access in a relatively short time, and these networks can provide a wide range of new energy services and a few nonenergy services. The disadvantages of ARM networks are that regionally dominate suppliers of meter communication services may limit competition once they are established, and reliability is an issue because of the cost associated with dedicated backup systems.

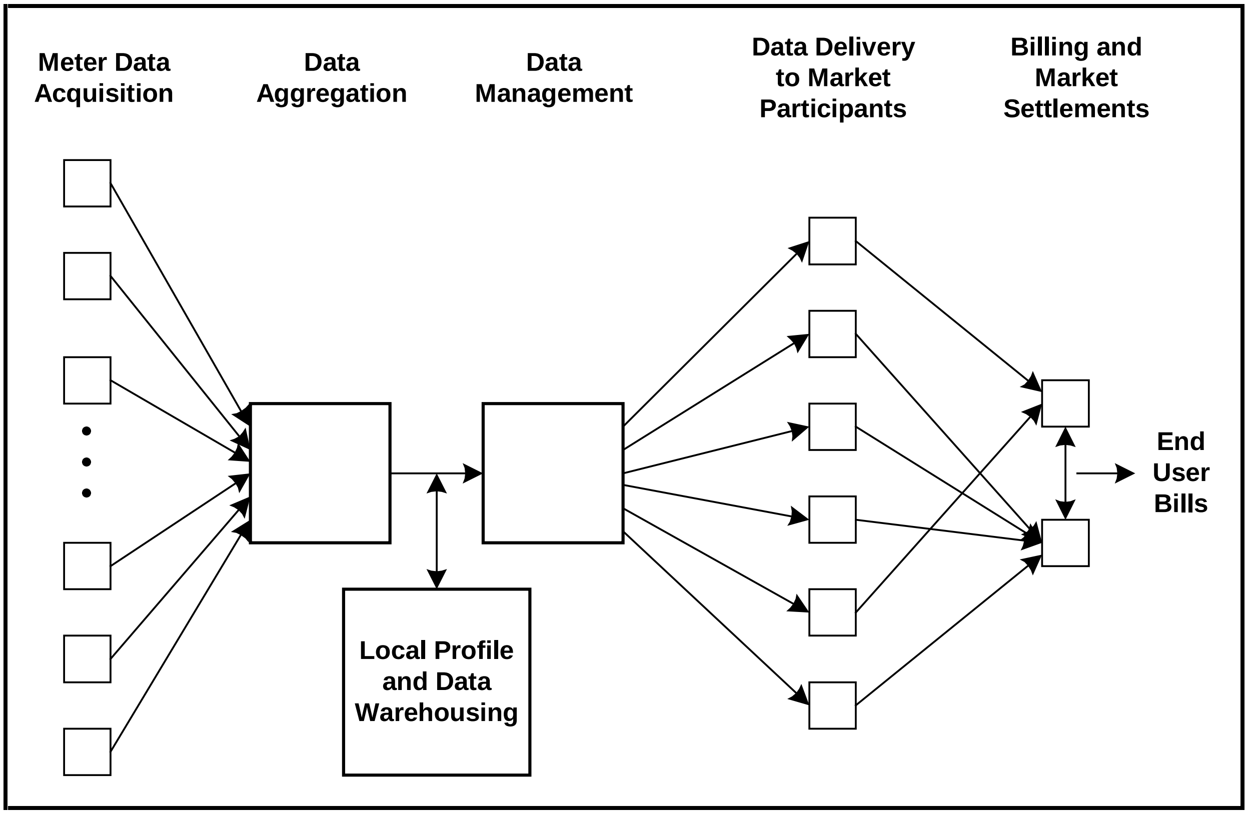
Transparent networks, such as the Internet, have the advantage that diverse applications will promote competition and provide the resource to support continued technical evolution, stimulating innovation and ensuring that capabilities expand to meet many market needs. In addition, the “cloud” structure of transparent networks such as the Internet increases reliability because of the availability of multiple communication paths.

The California Model

California has initiated one of the most comprehensive and largest applications of direct access metering and data communications (Shepherd, 1998). The California RTO is responsible for balancing generation supply and demand. The RTO is also responsible for settling imbalance deviations for market participants when day-ahead scheduling and actual generation and usage deviate (this is referred to as setting or direct access settlement). The RTO settlement process relies on scheduling coordinators to make daily reports of actual usage of each of their loads, aggregated to each grid supply point on an hourly basis. Hourly meter data are also required for all generating units.

Figure A-3 illustrates California’s metering, data communication, and settlement system to support their electric market. Utility Translation System, Inc.’s Meter Data Acquisition System (MDAS) is configured to read approximately 3,000 meters on an hourly basis to measure the total power supplied to the transmission grid from power plants and interchange points (state boundaries and for all grid supply points where power is taken from the transmission grid). The system retrieves data from meters through a dedicated ATM network using frame relay and ISDN lines. The system is designed to collect the meter information within 2 minutes and have it available in the data management system within 8 minutes.

Figure A-3. Information Flow to Support Billing and Market Settlements



The aggregation of meter data is a key function that must be performed before information can be dispatched for load profiling or settlement processes. Both load data and financial settlement use aggregation of load profiles from individual meters to generate virtual meters that represent loads by end use, class, multimeter accounts, delivery points, energy marketers, and utilities (Shepherd, 1998). Data compatibility is essential because of the large amounts of data being processed and the reliance on system automation.

Data delivery to market participants is complicated by the large number and the diversity of entities using the processed metering information. The potential number and variations of systems, architectures, and data formats that must be interfaced are huge. The delivery system must be able to support delivery of data in multiple file formats and to use various techniques for data delivery, including physical media (disk, CD), telephone, e-mail, and the Internet. There have been regional efforts in California to establish standard formats for data delivery, but none has been accepted on a broad basis. In addition, efforts are underway to establish standard electronic data interchange (EDI) formats to support transferring data between systems. The Internet has been targeted as a likely de facto standard for data transfer, but several issues are of concern, such as security and reliable transfer time.

The final step is the overall settlement process that compares aggregated day-ahead schedules with aggregated estimates/actual loads to calculate energy imbalances. The pricing components are input from a combination of sources such as spot market purchase prices, approved index pricing sources, and transmission control area charges. California uses metering data to support the pricing of the products and services, such as

- ancillary services,
- congestion management costs (re-dispatch and must-run),
- transmission services,
- RTO control area implementation and operating charges, and
- competitive transition charges (stranded access recovery).

Metering Equipment Manufacturers

The initial automatic meter reading projects began in the 1970s. Westinghouse R&D designed the first nonvolatile solid state memory chip for automated reading. It took readings from electric, gas, and water meters and sorted them in memory that did not require continuous power or battery back up to retain memory through a power outage. Darco (name later changed to Darcom) was a major contributor to the development of ARMs, designing and programming a Texas Instruments-built customer microprocessor chip for the Electric Power Research Institute's automatic meter reading functions.

Major manufacturers of meters today are listed in Table A-3. All of these companies mass produce both monthly meters and hourly meters.

Table A-3. Meter Manufacturers

ABB	OSC/Intelimeter
Computerized Manufacturing Corporation	Process Systems, Inc. (Siemens)
General Electric	Quadlogic Controls
Hiaweh Meter Company	Schlumberger
Itron Genesis	Teldata
Leach Industries—Amron	Transdata, Inc.
National Meter Company	

Currently, more than 30 companies provide or support advanced metering products or automatic meter reading systems capable of supporting hourly metering. These companies include

- CallNet Data Systems,
- ITRON,
- Landis & Gyr Utility Services,
- Polymeters Response International,
- Schlumberger Industries,
- UNITIL, and
- Utility Translation System.

Appendix B: Deregulation Background and Trends

Deregulation of the electric utility industry is an ongoing process. In particular, deregulation of wholesale markets is well underway. Wholesale market deregulation was initiated by the Energy Policy Act (EPAct) of 1992, and implementing rules were issued by the Federal Energy Regulatory Commission (FERC) in Orders 888 and 889. FERC Order 888 requires open access to the electricity grid and nondiscriminatory pricing of wholesale transactions. FERC Order 889 contains rules establishing and governing utility Open-Access Same-Time Information Systems (OASIS) and prescribing codes of conduct.

Deregulation of retail electricity markets is occurring at the state level. But states are moving at different rates. Some states have forged ahead and either allow, or will soon allow, electricity customers to choose among generation suppliers. Most of the other states have begun to address the issue of retail deregulation, but no formal plans are in place yet. States that have deregulated tend to be in regions with high electricity prices, but not exclusively so. The overall trend is clearly toward deregulation of retail electric markets, and the movement is gaining momentum.

This appendix provides a brief overview of the technology issues that have led to deregulation of electricity markets, and a discussion of the history of restructuring. The final section contains two tables that present the status (Table B-1) and progress (Table B-2) of retail electric deregulation across the United States as of January 2000.

B.1 TECHNOLOGY ISSUES LEADING UP TO DEREGULATION

The push for deregulation in the electric utility industry has not been the result of rapid technology advances, as has been the case in other industries, such as telecommunications. In fact, in many ways, it is the lack of technology advances and the tapering off of increased production efficiencies in large-scale generation that have fueled the deregulation movement in the electric utility industry. Since the birth of the electric utility industry up through the early 1970s, the cost of generation had continually decreased (usually in nominal, but always in real, terms). Over this period, consumers became accustomed to reliable and inexpensive electricity.

In the early 1970s, however, several factors combined to bring about the first real increases in the price of electricity. The two main components that had historically held prices in check—increased generating efficiency and rapid demand growth—no longer held true in the 1970s. The costs of generation could no longer be reduced by building larger plants as economies of scale in fossil fuel generation leveled off. In addition, the oil embargo and the push for national energy self-sufficiency in the 1970s spurred improvements in electric end-use equipment efficiency and led to the first decrease in kWh sales since 1946 (the transition from wartime to peacetime economy).

The sheer size of the construction projects for larger generation plants contributed to the reduction of economies of scale in generation. The magnitude of the projects strained the management and organizational limits and often led to construction delays and cost overruns. The combination of 10- to 15-year construction projects with the high inflation and high cost of capital of the 1970s also made constructing large-scale power plants uneconomical.

In the mid-1980s, regulatory commissions began reviewing the "prudence" of utilities' decisions to proceed with the construction of new large-scale generating plants. These reviews resulted in the disallowance of billions of construction dollars and signaled the end of large-scale construction projects. Environmental concerns of the late 1970s and early 1980s also led to increases in the cost of large-scale generation. Costly pollution abatement equipment for fossil fuel plants was phased in during this period. Sharply increased nuclear safety concerns in the aftermath of the Three Mile Island incident led the Nuclear Regulatory Commission (NRC) to require extensive and costly design modifications to planned nuclear units and to nuclear plants under construction.

While efficiency gains in large-scale generation were leveling off, advances in transmission technology enabled the transportation of large blocks of power over long distances with improved reliability and lower cost. Traditionally, transmission lines had a voltage capacity of less than 200 kilovolts and could transmit power effectively only over a short distance. With the introduction of high-capacity lines of close to 1,000 kilovolts, line loss was greatly reduced.

Innovations in the natural gas industry also played a major role in the move toward deregulation in the electric industry. With new seismic and drilling technologies, supply at the wellhead became more reliable. Bottlenecks in the gas delivery system were worked out, and natural gas markets evolved, enabling electricity generators to contract for gas over long time periods. These factors contributed to the cost competitiveness of small-scale combustion turbine engines.

Also in the mid-1980s, new capacity construction costs for gas turbine engines decreased because of a combination of advances in turbine technology and economies of scale in engine production. Technological progress in combustion turbines led to higher firing temperatures, which resulted in increased efficiency for small-scale generation. In addition, when combustion turbines are coupled with heat recovery boilers to capture the exhaust heat, steam can be generated. This steam can be used for process use (cogeneration) or for generation of additional electricity with steam turbines.

In conclusion, the main technology issue leading to the push for deregulation in the electric utility industry has been the leveling off of efficiency gains from large-scale generation and the increased competitiveness of small-scale generation due to technology advances and low gas prices.

B.2 BRIEF HISTORY OF RESTRUCTURING

The vision behind the restructuring of the electric power industry is the creation of a competitive generation sector that would replace the historic generation monopolies. The Public Utility Regulatory Act of 1978 and the National Energy Act of 1992 encouraged the introduction of independent power producers (IPPs) and began building the diverse generation base needed to support a competitive generation sector. However, in the 1980s and early 1990s the IPPs were still primarily limited to selling their power to local utilities at prices set by regulatory agencies.

In 1993, Alberta was the first region in North America to establish a competitive wholesale spot market for electric generation. At about the same time, British Columbia was also developing plans for short-term markets. In April 1994, California followed with a proposal to phase out its retail electric monopolies and offer customers direct access to competitive generation markets. However, the growth of regional spot markets was hampered by the lack of an "open grid" that would support the large-scale interregional market transactions associated with a truly competitive generation sector.

FERC 888 was issued in April 1996 with the intent to provide open access to transmission for all generators. It orders that private owners of transmission assets offer competitors access to their grids on the same terms afforded their own generation units. As part of the order, public utilities that own, operate, or controll transmission facilities are required to file open access nondiscriminatory transmission tariffs. Tariffs are specified to provide service on both a network basis and a flexible point-to-point basis: the network service is a load-based service, and the point-to-point service is based on transmission capacity reservations (FERC, 1996).

At the same time FERC issued Order 889 containing rules for establishing and governing an OASIS and prescribing standards of conduct. FERC 889 orders public utilities that own, operate, or control transmission facilities to create or participate in an OASIS that would provide open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that would enable them to obtain open access to nondiscriminatory transmission service (FERC, 889). Section J of FERC 889 document specific standards and communications protocols to support the electronic transfer of information.

B.3 PRESENT STATE ACTIVITY

The present pace and details of restructuring vary greatly from state to state. By mid-1999, 20 states and the District of Columbia, an area containing over half of the U.S. population, had formally decided to restructure and move toward some form of market-based generation (Cavanagh, 1999). Another ten states are actively engaged in some form of legislative or regulatory activity with the goal of bringing retail electricity competition. Seventeen states have established legislative study committees, and only three states were not actively pursuing any reform (APPA, 2000). Table B-1 indicates where all 50 states and the District of Columbia fall on this spectrum.

Table B-2 provides more detail and information on all of the states that have enacted legislation and some of the states that have seen significant activity towards enacting legislation. This table is based on data from the Energy Information Administration and is current as of January 2000.

Among the states that have moved to a competitive retail electricity market, California has been a leader. In March 1998, some Californians had the opportunity to select their electric supplier over a transmission system operated with complete independence from all generation owners. By 2002, all Californians will be able to choose their supplier. In addition, the California independent system operator (ISO) has established an Internet-based system of communicating and monitoring generation units to support market transactions. Other states, like Maryland, have followed similar actions. A retail access bill was signed in April 1999, allowing one-third of residential customers to choose their supplier by July 2000 and the remaining two-thirds of retail customers to choose their supplier by July 2001. States that have enacted legislation are predominately located in the Northeast (Maine, Rhode Island, Pennsylvania) and the Southwest and West Coast (Texas, California, New Mexico).

States that have engaged in some legislative or regulatory activity have focused on achieving similar goals for retail customers as the states that have already enacted retail competition. For example, a bill was introduced into the Michigan legislature in January 2000 that is designed to give customers free choice over their electricity suppliers by January 2002. Other states, like Louisiana, have decided to move towards competition and will enact policy changes by 2001. States that have seen major regulatory or legislative activity are located in the Midwest (Indiana, Wisconsin) and the Deep South (Alabama, Mississippi).

A third group of states has not made a decision to pursue retail competition; they are maintaining vertically integrated monopoly power systems while they are deciding if they should pursue competition. For example, Utah passed legislation in 1997 to form a study committee to determine the impacts of competition in Utah.

The main outcome of their study has been to adopt a "go slow" approach and wait until the impacts from other states are better understood. South Carolina also passed legislation in 1997 that has been renewed each year since then to continue the study process. States that are currently using legislative study committees are located in the Southeast (Georgia, North Carolina) and the Rocky Mountain area (Colorado, Nebraska).

Florida, Hawaii and South Dakota are not currently engaged in any form of restructuring. These states are not pursuing any form of deregulation nor have they created study committees to determine if they should. However, these states have pursued deregulation in the past. For example, Florida has introduced bills calling for competition and for study committees; however, they have never passed. South Dakota, on the other hand, has no desire to pursue deregulation. South Dakota is one of cheapest power states in the country, and deregulation would provide little, if any, benefit to the predominantly rural population.

Table B-1. Status of Present State Activity, January 2000

Enacted Legislation	Legislative or Regulatory Activity	Study Committee	No Present Activity
Arkansas	Alabama	Alaska	Florida
California	Arizona	Colorado	Hawaii
Connecticut	Indiana	Georgia	South Dakota
Delaware	Iowa	Idaho	
District of Columbia	Louisiana	Kansas	
Illinois	Michigan	Kentucky	
Maine	Mississippi	Minnesota	
Maryland	New Hampshire	Missouri	
Massachusetts	New York	Nebraska	
Montana	Wisconsin	North Carolina	
Nevada		North Dakota	
New Jersey		South Carolina	
New Mexico		Tennessee	
Ohio		Utah	
Oklahoma		Washington	
Oregon		West Virginia	
Pennsylvania		Wyoming	
Rhode Island			
Texas			
Vermont			
Virginia			

Source: American Public Power Association (APPA). 2000. "Status of State Electric Utility Deregulation." <http://www.appanet.org>.

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000

State	Status of Restructuring Activity
Alaska	
Additional Information	1/99: Chugach rejected Matanuska's offer and contended that the savings projected by the merger could easily be achieved through competition; Chugach will continue to push for statewide competition.
	10:98: Matanuska Electric Association, Chugach's largest wholesale customer, offered to buy out Chugach. Chugach's assets are valued at $486 million. Chugach officials were surprised by the offer and are withholding judgment.
	6/98: PUC rejected Chugach's argument and affirmed the Public Utility Commission's (PUC's) authority to regulate retail wheeling.
	1/98: Chugach Electric Association, the state's largest utility, urged PUC and legislators to allow retail competition in Anchorage and surrounding areas. House Bill 235 primarily failed because Chugach would not support it unless it was amended to allow retail wheeling in Anchorage and surrounding areas.
Arizona	
Schedule	1/00: APS and TEP have opened 20 percent of their retail load to competition, APS in 10/99 and TEP in 1/00. Salt River Project began phasing-in retail access in 12/98. All customers in the state will have retail access by 1/01.
	11/99: The ACC approved Tucson Electric Power's restructuring settlement. TEP will open 20 percent of its load to retail competition by 1/00
	9/99: APS will open 20 percent of its territory to competition on 10/1/99, and all of it by 1/01.
	7/99: The first customers to take advantage of retail choice began receiving power from APS Energy Services in July. The two industrial customers are in the Salt River Project's service territory. Salt River Project opened 20 percent of its territory to retail competition in 12/98, and will open the rest by 12/00.
	1/99: The Salt River Project opened about 20 percent of its market to retail competition in 12/98.
Rates	11/99: TEP's settlement agreement was approved and requires a 1 percent rate reduction and a rate freeze through 2008.
	9/99: APS's settlement agreement was approved. Residential rates will be reduced 7.5 percent over 4 years, and large users' rates 5 percent over 3 years.
	5/99: In the proposed APS settlement agreement, rates will be reduced 7.5 percent for residential and small business customers and 5 percent for industrial customers over the next 4 and 3 years, respectively. If approved, the residential and small business reductions would total 16 percent over 10 years, including the rate reductions from 1994. TEP's settlement includes a more modest rate reduction of 1 percent in 7/99 and in 7/00 with rates frozen at the 7/00 level until 2008.
	1/99: The Salt River Project's restructuring plan includes a 5.4 percent residential rate reduction.
Utility Plans	11/99: The ACC approved TEP's restructuring agreement. The agreement will allow recovery of $450 million in stranded costs collected from ratepayers through 2008; rate reductions of 1 percent and frozen from 7/00 to 2008; and retail access beginning with 20 percent of TEP's retail load 60 days after ACC approval (1/00), and all customers by 1/01. TEP's generation assets will be transferred to an affiliate company by the end of 2002.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Arkansas	
Schedule	5/99: Legislation sets retail competition to begin by 1/1/02. Implementation of retail competition can be delayed by the Public Service Commission (PSC), but no later than 6/30/03.
Rates	5/99: Rates for consumers of utilities seeking to recover stranded costs will be frozen for 3 years, and for those not seeking to recover any stranded costs, 1 year.
Utility Plans	12/97: Arkansas PSC agreed to Entergy's restructuring plan. The plan includes rate reductions of about $217 million over 2 years; debt reduction of $165 million over 5 years on the Grand Gulf Nuclear Station; and creation of a special transition cost account to collect funds for stranded costs recovery.
California	
Schedule	1/00: As of 1/15/00, the PUC reports 209,752 direct access customers (2.1 percent) out of 10,157,716 possible utility distribution customers. The direct access customers represent 13.8 percent of the total load. Almost one-third of the demand by large industrial customers is being served by competitive companies, whereas only about 2.1 percent of residential load is on direct access.
	6/99: As of 5/31/99, the PUC reports that 135,493 California consumers (about 1.3 percent) have switched electricity providers. The breakdown by customer class is: 92,904 residential consumers or about 1.1 percent; 26,942 small commercial (2.8 percent); 11,652 large commercial (5.9 percent); 1,002 large industrial (20.6 percent); 2,977 agricultural (2.5 percent); and 16 unknown. About half of the consumers who have switched suppliers have opted for "green" power, electricity generated from environmentally acceptable methods, such as wind, solar, and geothermal.
	10/98: Based on California Public Utilities Commission (CPUC) data, New Energy Ventures, a retail electricity marketer, calculated it has won about 40 percent of the 13,648 GWh load being served by nonutility energy service providers.
	4/98: The CPUC issued the final order to open the retail market on 3/31/98; all consumers in investor-owned territories could choose alternative electricity suppliers.
Rates	6/99: The CPUC ended the mandatory 10 percent rate reduction for San Diego Gas & Electric (SDG&E) since the transition period for SDG&E ended with recovery of all stranded costs and the end of the competitive transition change (CTC) for consumers. Rates in SDG&E's territory are now unregulated and likely could be more volatile. The utility expects rates may rise during the summer months.
	5/99: SDG&E's consumers may see lower bills as the transition period for SDG&E ends in July when their stranded costs will have been completely recovered. The accelerated pay-off of stranded costs has left most of the monies raised through securitization to finance the 10 percent rate reduction with bonds unneeded. SDG&E plans to return some of the funds to small consumers. SDG&E also asked the PUC to end the rate cap, which should allow a more competitive market to develop.
	4/98: California's restructuring legislation included a 10 percent rate reduction for residential consumers.
Utility Plans	6/99: Los Angles Department of Water and Power is offering a "green power" option to its customers.
	5/99: Sacramento Municipal Utility District approved a direct access program to replace their pilot program. The program will offer 300 MW of load to competitive suppliers and is less expensive and simpler for suppliers than the pilot program.
Additional Information	7/99: To date, over 90 percent of customers who switch their electricity providers are receiving green power. The CPUC reports show customer requests for green power are up 90 percent from earlier in the year. A statewide credit for renewable energy purchases allows green power providers to offer renewable-based electricity at a price below that offered by the three major IOUs.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Connecticut	
Schedule	6/99: The Department of Public Utility Control (DPUC) is concerned that no suppliers have yet applied for licensing to serve the market when it opens 1/00. Part of the lack of interest may be because the rules for standard offer service and estimated stranded cost recovery are not yet finalized by the Attorney General and the state General Assembly.
	4/99: The DPUC ordered generation charges to be shown as a separate charge beginning 7/99. Bills will be completely unbundled as of 1/00. Suppliers will begin licensing as early as 7/99 and soliciting of customers will begin.
	4/98: Restructuring legislation requires retail competition for 35 percent of consumers by 1/00, and all consumers by 7/00.
Rates	4/98: Restructuring legislation requires a 10 percent rate reduction beginning 1/00.
Utility Plans	8/99: The DPUC gave a preliminary order for stranded cost recovery of $726 million instead of the requested $916 million to United Illuminating (UI).
	6/99: UI's plan for unbundling its generation assets was approved by the DPUC. UI plans to place its nuclear assets in a separate division from 10/99 until they are divested through public auction.
	10/98: UI filed its divestiture plan with the PUC to sell its nonnuclear generating assets. Plants being sold include the 590 MW Bridgeport Harbor and the 466 MW New Haven Harbor plants. Also in filing are plans on how to unbundle the generation business from the wires or distribution business. UI will become a "wires" company responsible for power delivery.
Delaware	
Schedule	9/99: The PUC issued final orders for restructuring in Delaware. Start date for competition is 10/1/00 for residential customers, 10/1/99 for large customers, and 1/15/00 for medium-sized customers.
	Conectiv (DP&L)—Phase-in of retail access for consumers in Conectiv's territory is for large industrial consumers on 10/1/99; other consumers with over 300 kW demand by 2/00; and small consumers by 8/00. DP&L will be the default supplier during the 4-year transition period.
	Delaware Electric Cooperative—Consumers in Delaware Electric Cooperative territory will have a similar schedule with a 6-month delay. Municipals in Delaware may choose whether to allow retail access.
Rates	4/99: Conectiv (DP&L) residential consumers will receive a 7.5 percent rate reduction and a 4-year rate freeze from 10/1/99 to 9/30/02. Nonresidential consumers also will receive a rate freeze for the same period.
	DE Electric Cooperative—Consumers will receive no further rate reduction (having received a recent 5 percent cut) but will have rates frozen for 5 years.
Utility Plans	5/99: Conectiv announced its restructuring plan to prepare the company for competition. It will sell its three fossil-fuel plants and interest in five nuclear plants used for baseline generation and retain peaking gas units. It plans to expand its telecommunications business.
	4/99: Restructuring plans for Conectiv and DE Electric Cooperative will be filed by 4/15 and 9/15, respectively.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
District of Columbia	
Rates	3/99: Potomac Electric Power Company's (PEPCO's) restructuring plan proposes a 5-year rate freeze.
Utility Plans	3/99: PEPCO plans to sell its power plants and purchase power contracts. PEPCO intends to become a "wires" company, concentrating on power delivery, retailing power, cable TV, and Internet services.
Georgia	
Utility Plans	6/98: Georgia Power submitted a 3-year plan to reduce rates by about $300 million. Georgia Power advocates a slow approach to restructuring.
Additional Information	New customers with loads greater or equal to 900kW have had the option to pursue private contracts for power since1973 under the Georgia Territorial Electric Service Act.
Illinois	
Schedule	11/99: Direct access began in 10/99 for many commercial and industrial consumers. Loads over 4MW and multisite (at least ten sites) customers with aggregate loads over 9.5MW are automatically included in this first phase to implement retail access. A lottery was held at each utility to choose consumers to allow about one-third of the remainder of commercial and industrial load to participate in the first phase. Media sources report that customers in Commonwealth Edison's service territory are realizing 5 to 15 percent savings from competitive companies.
	7/99: The General Assembly amended the 1997 restructuring law, accelerating the schedule for retail access: certain nonresidential consumers will begin retail access by 10/99. Government customers will have direct access by 10/1/00; all remaining nonresidential customers by 12/31/00; and all residential customers by 5/1/02.
	4/99: The sign-up process for eligibility to choose is under way at each utility. Loads over 4MW and multisite (at least ten sites) customers with aggregate loads over 9.5MW are automatically included. Interested consumers will sign up and a lottery will be held to determine the one-third of nonresidential load (excluding the 4MW and 9.5MW aggregated loads) that will have retail choice by 10/99. The remainder of commercial and industrial consumers not chosen in this lottery will get retail choice on 12/31/00, and residential consumers will have retail access by 5/1/02.
	12/97: The restructuring legislation in Illinois will allow retail access for some commercial and industrial consumers by 10/99 and all consumers by 5/02. Transition charges will be collected from consumers who choose alternative suppliers until 2006.
Rates	3/99: ComEd's residential customers have saved approximately $170 million as a result of the 15 percent rate reduction on 8/1/98.
	10/98: As required by the restructuring law in Illinois, a 15 percent rate reduction went into effect in 8/98. To date, Illinois Power customers have saved about $12.5 million.
	8/98: The phase-in of rate cuts took effect. The state's largest utilities, Illinova and Commonwealth Edison, cut rates 15 percent; another 5 percent reduction is due 5/02. Smaller utilities will phase-in 5 percent reductions by 5/02.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Illinois (continued)	
Utility Plans	8/99: Ameren and Cilco both held lotteries to choose the one-third of eligible customers that will receive retail access. All customers over 4 MW are automatically eligible, and one-third on the load for nonresidential customers will be available to competitive suppliers beginning 10/1/99. Lotteries were held because more than a third of the customers expressed the desire to be included in this first phase of retail access in Illinois. Those customers not selected in these lotteries will have retail choice in 2000. Residential customers will have retail choice in 5/02.
	7/99: ComEd held three lotteries (one for single-site consumers, one for commercial consumers with at least ten sites and an aggregated demand of at least 9.5 MW, and one for nonresidential consumers with two or more sites; customers with loads 4 MW and more are automatically included) to choose the one-third of consumers to have retail access by 10/99. Over half of the commercial and industrial consumers in ComEd's territory are registered for retail choice. ComEd announced the resultant energy freed for competition will be over 30 billion kWh. In Illinois Power's service territory, all commercial and industrial customers who registered will begin retail access 10/1/99. Only about 75 percent of those eligible in Illinois's territory registered.
Indiana	
Utility Plans	7/98: Consumers of Indianapolis Power & Light were offered three billing options. Consumers can choose a fixed rate, a fixed monthly bill based on last year's average bill, or a "green power" rate under an alternative pricing plan approved in 3/98 by the Indiana Utilities Regulatory Commission.
Maine	
Schedule	1/99: Maine consumers will begin seeing itemized bills in 1/99 that separate the costs of power generation from delivery. The restructuring law requires unbundled billing by 1/1/99.
	5/97: Restructuring legislation requires retail competition by 3/00. IOUs are limited to 33 percent of the market in their territories.
Utility Plans	5/98: PUC approved Central Maine Power's corporate reorganization into a holding company, CMP Group, Inc., and distribution and transmission services. A new unit, Maine Power, will market electricity.
Maryland	
Schedule	4/99: Restructuring legislation allows retail access over a 3-year phase-in period beginning 7/00 with a third of consumers, another third by 7/01, and all by 7/02.
Rates	9/99: PEPCO is seeking approval of its deregulation plan that will include a 3 percent rate reduction over 4 years beginning in 7/00, and another 4 percent reduction by eliminating a surcharge that has funded energy conservation programs over the last decade.
	4/99: Restructuring legislation requires at least a 3 percent rate reduction for residential consumers.
Utility Plans	01/00: Allegheny Energy Inc.'s settlement plan for restructuring was approved by the PSC in 12/99. Highlights of the plan include retail direct access for almost all Maryland customers by 7/1/00; a 7 percent residential rate reduction, effective 1/1/02 through 12/31/08; a cap on residential generation rates from 1/1/02 through 1/1/08; a cap on nonresidential rates through 1/1/04; a cap on transmission and distribution rates for all customers from 1/1/02 through 1/1/04; authorization to transfer all generation assets to Allegheny's unregulated affiliate company, Allegheny Energy Supply Company, LLC, at book value; the recovery of purchased power costs incurred as the result of contracts with PURPA qualifying facilities; and establishment of a fund for the development and use of energy-efficient technologies.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Maryland (continued)	
Utility Plans (continued)	1/00: PEPCO's restructuring plan was approved by the PSC. The plan will allow retail direct access by 7/00; the sale of PEPCO's power plants; a 7 percent residential rate reduction; and a 4 percent nonresidential rate reduction.
	12/99: PEPCO began a consumer education program, PEPCO Answers, to provide information to Maryland consumers on electricity competition. Consumers were told that they may begin "shopping" for power in the spring of 2000 and begin receiving power from competitive companies by 7/00. PEPCO has filed proposals with the Maryland and District of Columbia PSCs to sell its power plants.
	9/99: Under its pending restructuring plan, BG&E's shopping credit for residential consumers would be 4.224 cents per kilowatt-hour and rise to 5.02 cents in 6 years, too low according to competitive companies seeking to enter the retail electricity market in Maryland. The Mid-Atlantic Power Supply Association suggests the credit be set at 5.7 cents; BG&E says the low credit reflects its low prices.
	6/99: The restructuring legislation prompted Maryland utilities to revise their restructuring proposals. BG&E submitted its new plan to the PSC: all customers will have retail access beginning 7/00; residential rates will be decreased 6.5 percent beginning 7/00; $528 million in transition costs will be recovered over 6 years from customers; rates will be unbundled and generation assets transferred to an affiliate company; and BG&E will provide the initial funding of a low-income assistance fund and act as default supplier for customers deciding not to switch suppliers.
	4/99: PEPCO reached an agreement for restructuring. It will open retail competition to all of its consumers on 7/1/00. PEPCO is selling its generation assets and will use the profits to offset stranded costs. Remaining stranded costs will be collected from consumers paying a transition charge. Rates will be capped for 3 years at the 7/1/00 level.
	2/99: PEPCO signed an agreement with the Maryland PUC for a plan to bring retail choice to its Maryland consumers as early as next year. The plan requires Maryland legislation and concurrence with the District of Columbia PUC for the sale of PEPCO's power plants.
Additional Information	4/99: The restructuring legislation gives municipalities the option to implement retail direct access.
Massachusetts	
Schedule	2/99: Standard offer service (SOS), set for 1998 at 2.8 cents/kWh, rose to 3.5 cents/kWh for 1999, which should enable some suppliers to offer electricity competitively. SOS will gradually increase to 5.1 cents/kWh in 2004. By 3/05, SOS will end and all customers are expected to take competitive generation service.
	6/98: Customers in Massachusetts are beginning to sign up to purchase power from competitive suppliers.
	11/97: Restructuring legislation requires retail access by 3/98.
Rates	10/98: NEES subsidiaries, Massachusetts Electric and Nantucket Electric Company, report savings for their consumers of $67.5 million due to rate reductions. The state's restructuring law reduced rates by 10 percent. The sale allowed additional rate reductions prior to the law's further requirements in 1 year.
	11/97: Restructuring legislation requires rate reductions of 10 percent by 3/98 and another 5 percent 18 months later.
Additional Information	10/99: By the first quarter of 1999, about 1.3 percent of retail sales were supplied by competitive suppliers, representing about 0.13 percent of customers, most of which are large industrial consumers.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Massachusetts (continued)	
Additional Information (continued)	9/98: PG&E Corporation's subsidiary, PG&E Energy Services has secured a multiyear contract with the Massachusetts High Technology Council (with over 200 members) to provide electricity to its members. This is the largest aggregation of customers in the U.S., representing about 1.2 million MWh annually.
	6/98: Massachusetts' utilities received no bids for SOS or default power supply. Western Massachusetts Electric has asked the Department of Telecommunications and Energy (DTE) to remove the price cap on SOS, hoping to attract suppliers. SOS is set at 2.8 cents/kWh for consumers this year; bids were sought for no higher than 3.2 cents/kWh.
Michigan	
Schedule	1/00: The second phase in Consumers Power's plan to gradually implement retail direct access now allows 300 MW of load to be served by alternative suppliers. As in the first round of bids for 150 MW, the second set of bids exceeded the 150 MW of allotted capacity. Three more blocks of 150 MW each are scheduled to be offered for direct access on 12/27/99, 2/28/00, and 10/30/00. By 1/02, all consumers will have direct access to retail electric power.
	1/00: Detroit Edison customers participating in Phase I of the customer choice program began taking power from alternative suppliers in 12/99.
	12/99: The first phase of retail access was implemented in 9/99 with full participation in Detroit Edison's territory. The second phase began in 11/99. Each of five phases will make 225 MW of capacity available for all classes of consumers, until beginning in 1/02, when all consumers will have retail direct access to competitive generation provider companies.
	5/99: Seven large consumers of Detroit Edison can begin buying power from competitive suppliers on 6/1/99. Choice will be phased in for all Detroit Edison consumers by 1/02.
	3/99: The PSC plan is for 2.5 percent of consumers of Detroit Edison and Consumers Energy to choose electric suppliers beginning 9/99, and adding an incremental 2.5 percent every 6 months until 1/1/02, when all consumers of Detroit Edison and Consumers Energy will gain retail access.
Utility Plans	3/99: The PSC gave final approval to the retail choice implementation plans for Detroit Edison and Consumers Energy. A phase-in period for retail access will begin on 9/20/99.
	6/98: Detroit Edison and Consumers Energy filed revisions of draft plans that address comments from the MPSC staff, customers, suppliers, and other interested parties. Both plans will phase-in retail competition over the next 4 years beginning with large industrial consumers by 11/98 and full retail access by 1/1/02.
Montana	
Schedule	3/98: Montana Power accelerated its schedule for residential and commercial customers' pilot program. All customers will have retail access by 4/00, 2 years earlier than the law requires.
	4/97: Senate Bill 390, the Electric Utility Industry Restructuring and Customer Choice Act, was enacted allowing large industrial consumers retail access by 7/98 and all consumers by 7/02.
Rates	4/97: The restructuring law includes a 2-year rate freeze beginning 7/98.
Utility Plans	11/98: The PSC reached an agreement with Pacificorp to proceed with the sale of its service territory in the state to Flathead Electric Cooperative. Pacific Power (Pacificorp's Montana division) has about 34,500 customers.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Nevada	
Schedule	6/99: AB 366 delays the opening of the retail market by 3/00 and gives the governor, rather than the PUC, the authority to select another date if he deems it in the best interest of consumers.
	4/99: The Senate committee approved a bill that would delay retail access until 3/00 and freeze rates until 3/03.
	7/97: Restructuring legislation directs the PUC of Nevada (formally the PSC) to establish a market in which customers have access to potentially competitive electric services from alternative suppliers no later than 12/31/99.
Rates	6/99: AB 366 freezes rates from 3/00 through 3/03.
New Hampshire	
Schedule	10/98: Granite State will begin retail choice in its service territory upon the closing of the sale of NEP's nonnuclear generation assets or by 7/1/98, whichever occurred first.
	4/98: Legislators are discussing a delay until 1/31/99 for beginning retail choice in the state or authorizing the PUC to postpone the date indefinitely, due to the delay until November of the stranded costs case brought by PSNH.
	5/96: House Bill 1392 was enacted, requiring the PUC to implement retail choice for all customers of electric utilities under its jurisdiction by 1/1/98, or at the earliest date that the Commission determines to be in the public interest, but no later than 1/1/98.
Utility Plans	8/99: Public Service of New Hampshire (PSNH) filed a settlement plan with the PUC that will give consumers an 18 percent rate cut and allow retail competition to finally begin. Under the agreement, customers would pay $1.9 billion in stranded costs (PSNH would write off about $225 million in stranded costs, the largest disallowance of stranded cost recovery at a U.S. utility to date).
	9/98: Unitil (subsidiaries include Concord Electric, Exeter & Hampton Electric, and Fitchburg Gas & Electric) filed its restructuring settlement agreement with the PUC. In the agreement, Unitil will sell its New Hampshire power supply portfolio and be allowed to recover 100 percent of stranded costs over 12 years. Customer choice will be phased-in beginning 3/1/99.
	8/98: PUC ruled that New Hampshire Electric Cooperative can offer customers choice if FERC approves the "interpretation of its contract" for power purchases with PSNH.
	6/98: The PUC gave approval to a settlement, the first in the state, with Granite State Electric to bring retail competition to the electricity market. Under the settlement, Granite State customers could see a 17 percent rate cut and choose their generation supplier as early as July.
	4/98: Granite State restructuring plan is approved by PUC and the governor. Retail choice will begin 7/98 regardless of other utilities in the state. A 10 percent rate reduction will go into effect and, after divestiture of generation assets, a 17 percent reduction. Stranded cost recovery is set at 2.8 cents/kWh, decreasing by 50 percent once divestiture is completed.
Additional Information	4/99: Restructuring is at a standstill due to federal court rulings concerning the PUC's efforts to set stranded costs and rates for PSNH. The continuing federal court cases could delay restructuring efforts in the state for years.
	12/98: U.S. Circuit Court of Appeals ruled in favor of a lower court ruling, preventing the NH PUC from implementing deregulation, advancing PSNH's lawsuit over the plan to trial. The trial is set for 2/99.
	6/98: U.S. District Court issued an order enjoining the PUC from implementing any restructuring plans until the court holds trial for the suit filed by PSNH, scheduled in November.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
New Hampshire (continued)	
Additional Information (continued)	5/98: The New Hampshire Supreme Court heard arguments in the PSNH rate agreement case. A ruling is expected early in June.
	1/98: The PUC formally delayed the 1/98 start of retail competition to 7/98 due to the continuing litigation between the PUC and PSNH.
	3/97: PSNH filed a complaint with federal district court requesting the court enjoin the PUC restructuring plan, due to basing stranded cost recovery on market forces rather than utility costs. The court issued a stay on the plan as it applies to PSNH.
New Jersey	
Schedule	12/99: Customers in New Jersey began receiving power from their suppliers of choice on 11/14/99.
	8/99: As a result of legislation passed 2/99, retail choice for all consumers became a reality on 8/1/99 in New Jersey.
	3/99: New Jersey plans to launch its consumer education for electricity restructuring and retail choice program on 6/1/99.
Rates	8/99: Retail rates were reduced 5 percent on 8/1/99 as required by restructuring legislation. Further rate reductions will increase to 10 percent. The reductions must be sustained for 48 months from the start of direct access.
Utility Plans	7/99: Conectiv has received final approval from the BPU for its restructuring plan. The plan will give consumers retail choice by 11/14/99, as the BPU has extended the date for delivery of power from alternative suppliers to allow utilities more time to get their computer systems ready for the change. Rates will be cut by 5 percent on 8/1/99, increase to 7 percent on 1/1/01, and increase to 10.2 percent on 8/1/02. Conectiv's distribution rate will be 2.1384 cents/kWh. The company is allowed $800 million in stranded costs recovery. Shopping credits, the rates which outside suppliers must compete, are set: residential credits will be 5.65 cents/kWh in 1999, 5.7 in 2000, 5.75 in 2001, 5.8 in 2002, and increase to 5.85 in 2003; commercial rates will begin at 5.18 cents/kWh and eventually increase to 5.7 cents; industrial rates range from 4.95 cents/kWh and go up to 5.65, depending on voltage and time-of-day usage.
	6/99: GPU's restructuring plan for offering customers retail choice as of 8/1/99, was accepted by the BPU. The settlement includes rate reductions in addition to the 5 percent due August 1 as required by the restructuring legislation. Customers of GPU subsidiary Jersey Central Power & Light will also receive another 1 percent reduction in 2000, 2 percent in 2001, and 3 percent in 2002. Average shopping credits (actual credits depend on consumer class) were increased to 5.13 cents/kWh for August 1999, 5.27 cents in 2000, 5.31 cents in 2001, 5.36 cents in 2002, and 5.40 cents in 2003. GPU will be allowed to recover $400 million in stranded costs. Originally they asked for $525 million.
	3/99: Public Service Electric & Gas proposed a deregulation plan to the BPU that would determine how PSE&G would operate in a deregulated environment, which is scheduled to begin in New Jersey on 8/1/99.
	8/98: BPU is reviewing PSE&G's and Atlantic City's Conectiv) restructuring plans.
	9/97: An Initial decision on the four investor-owned utilities' restructuring filings is set for May 1998. PSE&G's plan would provide full retail competition by 1/99, and Rockland Electric's by 5/99. GPU's (Jersey Central P&L) and Atlantic Energy's adhere to the BPU schedule
	7/97: The four investor-owned electric utilities in the state submitted three filings each to the BPU consisting of a rate unbundling filing, a stranded cost filing, and a restructuring filing.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
New Mexico	
Schedule	Legislation passed in 4/99 that will allow direct access to be phased-in over the next 3 to 4 years.
New York	
Schedule	Central Hudson Gas & Electric Phase I—9/1/98 includes 8 percent of load by 12/31/98. Phase II—1/1/99 includes 8 percent additional load by 12/31/99. Phase III—1/1/00 includes 8 percent additional load each year. Full Retail Access—7/1/01. Consolidated Edison Phase I—6/1/98 includes 1,042 MW (116 MW small loads and 926MW large loads). Phase II—4/1/99 includes an additional 1,000 MW from all customer classes. Phase II was reopened in August to fill the program to its targeted enrollment of 2,000 MW. Phase III—4/1/00 includes an additional 1,000 MW each year from all customer classes. Full Retail Access—12/31/01 or 18 months after RTO fully operational, whichever is sooner. Long Island Power Authority 8/99: Numerous large business customers in LIPA's Choice Program began receiving power in August from an alternative supplier, ConEdison Solutions. ConEd Solutions is supplying about 20 MW of power to over 100 facilities on Long Island. New York State Electric & Gas Phase I—8/1/98 includes all customers in Norwich and Lockport Division and all small industrial customers throughout service territory. Full Retail Access—8/1/99. Niagara Mohawk Power Phase I—9/1/98 includes transmission level customers >60KV. Phase II—9/1/98 includes all remaining customers with peak demands >2MW. Phase III—5/1/99 includes all remaining transmission and subtransmission customers >22KV. Phase IV—4/2/99 includes all residential customers. Phase V—8/1/99 includes all remaining nonresidential customers. Full Retail Access—8/1/99. Orange and Rockland Utilities Phase I—5/1/98 includes expanding the pilot program, PowerPick, to all customers (energy only). Full Retail Access—5/1/99 includes energy and capacity. Rochester Gas & Electric Phase I—7/1/98 includes all customer classes, energy only, limited to 670 GWH annual energy total. Phase II—7/1/99 includes all classes, energy and capacity, limited to 1,300 GWH annual energy total. 7/99: RG&E is making an additional 10 percent of their system available to competitors. Phase III—7/1/00 includes all classes, energy and capacity, limited to 2,000 GWH annual energy total. Full Retail Access—7/1/01 includes all customers, energy, and capacity.
Rates	8/99: Niagara Mohawk received approval to reduce prices for the second consecutive year, beginning 9/1/99. The price reductions are part of NIMO's PowerChoice Plan. Average reductions for residential and small commercial consumers should be about 1 percent in addition to the approximate 0.8 percent effected last year. Another reduction scheduled for 9/1/00 will achieve overall reductions of about 3.2 percent. Industrial customers will receive larger reductions. Total savings for all customer classes under the 3-year Power Choice Plan will be about $600 million.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
New York (continued)	
Utility Plans	Consolidated Edison
	4/99: Phase II of ConEd's retail choice program began in April. Nearly 22,000 new customers are now enrolled, bringing the total customers in the programs to more that 68,000.
	12/98: ConEd began Phase II of its customer choice program. Enrollment of customers to exercise retail choice begins 1/99. The program will continue phasing in customers until all ConEd's customers have retail access in 2001.
	5/98: Because of oversubscription of ConEd's Phase I for retail competition, the load for residential and small commercial customers was doubled to 1,000 MW; a lottery will be conducted for large customers. Customers will begin receiving power from their suppliers of choice among more than 20 registered ESCOs on June 1.
	9/97: PSC approved ConEd's restructuring plan. The plan calls for rate cuts, retail competition to phase-in beginning 6/98, and full retail access by 12/01. In addition, ConEd will file by 1/98 unbundled tariffs for all classes of customers, to become effective 4/98. The plan calls for divestiture of at least 50 percent of ConEd's New York City fossil-fueled generation by the end of 2002.
	Central Hudson Gas & Electric
	2/98: PSC approved restructuring plan for Central Hudson Gas & Electric. The plan requires divestiture of fossil-fueled plants, a rate freeze until 6/30/01, rate reductions, and transition to full retail competition by 7/01.
	Long Island Power Authority
	11/98: Long Island Power Authority began retail access for 400 MW of load in 1/99 with a target of August for delivery of power from competitive providers. The first phase of direct access is split between residential (180MW), commercial, and government consumers. Phase II will open another 800 MW in 5/00. All customers of LIPA will have retail choice by 1/03.
	New York State Electric and Gas
	1/98: PSC approved New York State Electric & Gas's restructuring plan. The plan includes phase-in of retail competition for small industrials beginning 8/98, full retail competition by 8/99, a rate freeze and rate cuts, and divestiture of its coal plants by 8/99.
	Niagara Mohawk
	12/99: A competitive supplier, NYSEG Solutions, is offering NIMO residential customers a choice in generation supplier.
	2/98: PSC approved Niagara Mohawk's plan for rate restructuring, a nonbypassable CTC to fund $3.6 billion in debt for settlement with 16 IPPs to restructure uneconomic contracts, and divestiture of fossil-fueled and hydroelectric plants. Retail competition will begin in 1998 for large customers and be available to all customers by 1/1/00.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
New York (continued)	
Utility Plans (continued)	Orange and Rockland
	12/97: PSC settled Orange and Rockland's proposal for restructuring. O&R will phase-in retail competition beginning
	5/98: Allow full retail competitive by 5/99, provide rate cuts, and require divestiture of generation assets by 5/99.
	5/98: Orange and Rockland became the first utility in New York to offer retail choice through its Power Pick program as customers began to receive power from their suppliers of choice on 5/1/98.
	Rochester Gas & Electric
	1/98: PUC approved Rochester Gas & Electric's restructuring plan. RG&E will begin in 7/98 with open access for 10 percent of its customers and phase-in full retail access by 7/01. Divestiture of fossil-fueled and hydro plants and rate cuts is included in the plan.
Ohio	
Schedule	6/99: The restructuring legislation will allow retail customers to choose their energy suppliers beginning with a phase-in by 1/01 and completion by 12/05.
Rates	6/99: The restructuring legislation requires 5 percent residential rate reductions and a rate freeze for 5 years.
Utility Plans	1/00: First Energy filed a transition plan with the PUCO in 12/99. The plan includes unbundling the price of electricity into the components (generation, transmission, distribution, and transition).
Additional Information	6/98: The PUC approved Monongahela's tariff for conjunctive electric service, the first tariff approved that will allow groups of consumers to aggregate and negotiate the price for electricity.
Oklahoma	
Schedule	6/98: New restructuring legislation speeds up the time line for restructuring the industry and requires that all studies by completed by 10/99. Some retail competition should begin as early as 1999.
	4/97: The Electric Restructuring Act of 1997 allows retail competition by 7/02. The OCC is directed to study the issues and develop a framework to implement retail competition.
Oregon	
Schedule	7/99: The restructuring legislation will allow direct access for industrial and large commercial consumers beginning 10/00. Residential consumers will not have direct access to suppliers under restructuring, but will be provided a portfolio of pricing options, including a "green" rate, a market-based rate, and a traditional regulated rate.
Utility Plans	2/98: Portland General Electric's deregulation plan, which could become a model for the state, faces opposition from the Oregon Intervenor Coalition that includes Pacificorp, Washington Water Power, and consumer groups. Portland's plan calls for selling all its generation and allowing all customers to choose competitive generation suppliers. The coalition prefers a "portfolio model" for customer choice. The portfolio model would allow large industrial customers to shop for power suppliers, but small customers would continue to be served by the incumbent utilities and be offered a menu of plans to choose from. Options would include existing, market, or "green" rates.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Pennsylvania	
Schedule	1/99: About 475,000 customers (9.5 percent of eligible customers) have submitted paperwork to switch their generation supplier. Retail access will be available for two-thirds of the state's customers on 1/1/99.
	9/98: About 1.8 million customers have registered to choose their electric generation supplier. The customers have received a "How to Shop" guide and a list of competitive suppliers and are now in the process of making choices. All residential customers will receive an 8 percent rate reduction, and so far competitive suppliers will provide customers about 14 percent savings. Also, four "Green-e" products (a product with the Green-e logo is certified to be produced with 50 percent or 100 percent generation from renewables; see California) are being offered to Pennsylvania customers.
	8/98: The Electric Choice Program has enrolled 1.75 million customers and 70 electric service providers as of 8/1/98. In September, consumers will receive information on shopping for an electric service provider and the "shopping phase" will begin. Retail access is set to begin on 1/1/99.
	7/98: Pennsylvania consumers began signing up to participate in the first phase-in of competition. In the first week, over 1.1 million consumers signed up for the Electric Choice Program.
Rates	8/99: Rates for PP&L customers will drop by about 1 percent. The rate reduction is the result of PP&L's securitization of a portion of its competition-related transition costs.
	1/99: The 8 percent rate reduction in PECO's restructuring plan took effect for the 1.5 million residential customers in PECO's service territory.
Utility Plans	Allegheny Power
	11/98: The PUC and Allegheny reached a compromise agreement. Allegheny will have a 3.16 cents shopping credit, retail choice will follow the schedule consistent with the rest of the state (two-thirds by 1/99 and all consumers by 1/00), and $670 million can be recovered in stranded costs over 10 years.
	5/98: The PUC approved Allegheny's West Penn to recover $524 million in stranded costs. Consumers will be phased-in beginning 1/99 and going to full retail choice by 1/00.
	Duquesne Light
	5/98: PUC approved Duquesne Light's restructuring plan. Stranded cost recovery is set at $1.331 billion over 7 years beginning 1/99. Consumers should expect to save about 12 percent. Retail competition will be phased-in beginning 1/99 and be complete by 1/00.
	Pennsylvania Power & Light
	10/98: The PUC and PP&L reached an agreement on capacity prices; PP&L agreed to sell installed capacity at $19.72/kw-year through 1999.
	5/98: PP&L's restructuring plan was tentatively approved by the PUC. In the plan, PP&L will provide a 10 percent rate reduction and phase-in retail competition in thirds, beginning with two-thirds in 1/99 and all by 1/00. The amount of recoverable stranded costs allowed is $2.864 billion. Customers should see savings of about 10 percent.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Pennsylvania (continued)	
Utility Plans (continued)	GPU Energy 10/98: The PUC and GPU reached a settlement in GPU's restructuring cases, clearing the way for GPU customers to choose their electric generation suppliers on schedule beginning 1/99. 9/98: The PUC capped installed capacity (guaranteed access to a supply of electricity) prices at $19.72 per kilowatt-year. PP&L has argued that federal law allows capacity sale at "whatever the traffic will bear." Higher prices are keeping competitive power marketers out of PP&L's retail market where no competitor has been able to quote a price to beat PP&L's "price to compare" at 4.26 cents/kWh. 8/98: PP&L reached a settlement on its restructuring case. Under it, all consumers will get a 4 percent rate reduction. PP&L will be allowed $297 billion in stranded cost recovery over 11 years. Consumer choice will follow the same phase-in schedule. PECO 5/98: The PUC gave final approval to PECO's restructuring plan in a compromise agreement. Under the plan, PECO customers will receive an 8 percent rate reduction next year, 6 percent in 2000, with 20 percent savings expected for those willing to shop for power. PECO will be allowed to recover $5.26 billion in stranded costs over a period of 12 years. Two-thirds of customers will be phased in to retail competition by 1/99 and all customers by 1/00. UGI Utilities 6/98: The PUC approved restructuring plans for UGI Utilities, allowing $32.5 million of the requested $58.5 million in stranded cost recovery. 6/98: The PUC gave final approval to Pennsylvania Power & Light, Pennsylvania Power Co. (approved recovery of $234 million out of $273 million in stranded costs), and GPU's subsidiaries, Metropolitan Edison and Pennsylvania Electric. Also, the PUC authorized the Philadelphia Gas Works to sell retail electricity to its customers.
Additional Information	9/99: Restructuring in Pennsylvania is the most successful in the nation, in terms of the number of customers who have chosen alternative generation suppliers. About 450,000 customers in Pennsylvania have switched suppliers, a majority of them in the Philadelphia area, PECO's service territory. PECO had some of the highest prices in the state prior to deregulation. 4/99: Pennsylvania leads the nation in power shoppers. However, the Philadelphia City Council will examine why only 14 percent of eligible PECO consumers are taking advantage of up to 9 percent savings, above the guaranteed 8 percent savings given by PECO, and buying less expensive power that is available from competitive suppliers.
Rhode Island	
Schedule	9/99: As of 6/99, roughly about 2,000 customers out of the state's 456,000 have chosen alternative generation suppliers. 1/98: Retail access was implemented with 25 registered generation suppliers, but the standard offer interim rates (3.2 cents/kWh) offered by the state's IOUs are low enough that no real competition has occurred.
Rates	1/99: The standard offer rate increased from 3.2 cents/kWh to 3.5 cents. The increase should spur some competition in the state's retail electricity market. The standard offer rate will increase again to 3.8 cents in 1/00 8/98: Narragansett is proposing to cut rates 12.4 percent as a result of selling its power plants for $1.6 billion to U.S. Generating.

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Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Rhode Island (continued)	
Rates (continued)	5/98: PUC reluctantly approved a rate increase for Narragarsett Electric Company for its standard offer rate from the existing 3.2 cents/kWh to 7.1 cents/kWh by 2009. Similar increase were approved for Blackstone Valley and Newport Electric.
Texas	
Schedule	6/99: Restructuring legislation enacted in June will open the retail market for electricity by 1/02, except for customers of cooperatives and municipals that do not opt for direct access.
Rates	Utilities can freeze rates through 12/31/01. All customer classes will receive a 5 percent rate reduction on 1/1/02.
Utility Plans	12/97: Houston Light and Power (HL&P), Texas Utilities Electric Co., and Texas-New Mexico Power Co. announced agreements with the PUC on proposed competition plans, although final approval by the PUC is still needed. All three contain rate reduction measures. Texas-New Mexico's plan offers a guaranteed date, 2003, for full retail choice beginning with a phase-in of customers as early as 1/98 and a plan for stranded cost recovery.
	Texas Utilities
	3/98: PUC approved Texas Utilities' restructuring plan.
	Houston Light & Power
	10/97: HL&P presented its transition proposal for restructuring. Included is a 4-percent rate decrease over 2 years for residential customers.
	3/98: HL&P's restructuring plan was approved. The HP&L plan provides a 4 percent rate cut in 1998 and another 2 percent in 1999.
	Texas-New Mexico
	12/98: As part of Texas-New Mexico's transition to competition, the PUC approved a price reduction for their customers retroactive to 1/98, resulting in a credit on bills for customers. The price reduction is part of Texas-New Mexico's plan to reduce residential rates by 9 percent and commercial rates by 3 percent over a 5-year transition period.
	7/98: PUC approved Texas-New Mexico's 5-year transition plan. Along with the rate reductions (described below) are a provision for a pilot program and plans to allow retail choice of generation providers to all retail consumers by 2003.
	5/98: An administrative law judge recommended the PUC reject Texas-New Mexico's restructuring plan. The plan would provide residential customers an immediate 3 percent rate reduction and another 3 percent in 1/00 and 1/01, totaling 9 percent over 3 years. Also, the plan provided for full recovery of stranded costs through a CTC. A final decision by the PUC is expected by July.
Vermont	
Utility Plans	3/99: Central Vermont Public Service and Green Mountain Power filed a joint restructuring plan with the Public Service Board (PSB) of Vermont. The plan would consolidate the two companies into one distribution company and would have both companies sell their generating assets and focus on distribution and retail sales.

(continued)

Table B-2. Status of State Electric Industry Restructuring Activity as of February 1, 2000 (continued)

State	Status of Restructuring Activity
Virginia	
Schedule	3/99: Senate Bill 1269, The Virginia Electric Utility Restructuring Act, will allow retail direct access beginning on and after 1/1/02. The State Corporation Commission (SCC) will establish a phase-in schedule for customers by class. All customers will have direct access by 1/1/04.
Rates	8/98: The SCC approved more than $700 million in refunds and rate reductions. A total of $150 million in refunds will be provided by 11/2/98. In return for the refund/rate cuts, Virginia Power will use $220 million in revenue to reduce debt on generation assets.
	6/98: In an agreement between regulators, government, and business and Virginia Power, Virginia Power will refund $920 million, the biggest rate adjustment in Virginia history, in rate cuts and refunds over the next 5 years. The rate reduction refund agreement is subject to approval by the SCC. A public hearing is scheduled for 7/21/98 on the proposed settlement.
Wisconsin	
Rates	9/99: Wisconsin Electric Power Company requested that the PSC establish criteria for performance-based ratemaking. WEPC also submitted a request for a 3.1-percent rate increase.

Appendix C: Discussion Guide

Measurement and Standards Important to Deregulating the Electricity Industry

Thank you for agreeing to speak with us about measurement and standards issues important to the electric power industry. Below is a brief background on the study and its objectives. We have also included a discussion outline containing an overview of the issues we would like to cover during our conversation on October X at XX:00 a.m./p.m. Please feel free to share this with colleagues and solicit any insights they may have.

Background

The National Institute of Standards and Technology (NIST) recently commissioned Research Triangle Institute (RTI) to study technology trends in the generation, transmission, and distribution sectors of the electric power industry. As part of this analysis, RTI is assessing measurement and standards needs identified by power industry experts. The results of this study will be made available in a NIST publication and will be presented during a NIST-sponsored national conference on "New Challenges for Measurements and Standards in a Deregulated Electric Power Industry," which will be held December 6-8, 1999.

In general, we are interested in two topics: 1) analyzing the changing measurement and standards needs of the electric power industry as a result of deregulation, and 2) estimating the economic impact of meeting (or *not* meeting) these needs. Specific areas of interest include, but are not limited to, measurement and standards to support

- competitive metering,
- bulk power transactions and monitoring,
- reliable transmission and distribution of electric power,
- communications and control technologies,
- advanced diagnostics,
- power quality, and
- distributed generation.

Discussion Topics

To conduct our study, we are partitioning our discussion into three broad (admittedly interrelated) categories:

- **Efficiency Benefits of Restructuring**: measurement and standards needs to support/enhance projected increased system efficiency.
- **Issues Related to System Planning and Operation**: measurement and standards needs to support the planning and operation of power generation, transmission, and distribution.
- **Issues Related to Market Functions**: measurement and standards needs to support wholesale and retail customer billing and metering

For each topic, we would like to begin with a general discussion of restructuring issues and then ask what role measurement and standards may have in solving problems or enhancing benefits.

Efficiency Benefits of Restructuring

In general, what are the anticipated benefits associated with restructuring the electric power industry?

For example, will restructuring effect the overall economic efficiency of the electric power system? If so, how

- will restructuring decrease the average cost of generation?
- will restructuring decrease the average cost of ancillary services? Which ancillary services will be most affected? Will low cost suppliers enter the market. Will the unbundling change the available supply of certain ancillary services?

What are other benefits do you foresee associated with restructuring?

What do you foresee will be the additional costs that somewhat offset the economic benefits. For example,

- will restructuring affect total system monitoring and control costs?
- Will there be additional metering costs to support market functions?

Can measurement and standards play a role in enhancing system efficiency? If so, how?

For example,

- can measurement and standards reduce average generation or ancillary service costs? Approximately what percentage change in cost do you expect?
- can measurement and standards reduce total system monitoring and control costs? Approximately what percentage change in cost do you expect?

What are other areas where measurement and standards can enhance benefits or reduce costs from restructuring?

System Planning and Operations

What are the major difficulties facing system planning and operation associated with restructuring the electric power industry?

Transmission Capacity

Do you think restructuring will increase the demand for transmission services?

If so, what are the potential problems associated with the demand for transmission services outpacing the growth of new transmission capacity?

- ➤ Do you think transmission constraints will affect reliability?
- ➤ Do you think transmission constraints will affect power quality?
- ➤ What other specific areas will be affected?

How do you think the electric power system will respond to the increased transmission demand?

For example, will system planner and operators respond by

- ➤ building new transmission corridors?
- ➤ restringing existing towers to increase capacity?
- ➤ increasing capacity utilization of existing transmission system through better monitoring and control (introducing dynamic state control)?
- ➤ increasing the use of distributed generation?
- ➤ increasing the use of curtailable load programs?
- ➤ limiting whole sale transaction activities?
- ➤ other responses

  What is the relative importance of each area in alleviating transmission constraints?

What role can measurement and standards play in alleviating the transmission shortages?

Which response areas identified above are the most dependent on measurement and standards?

Can you roughly estimate the *total* magnitude of the potential effect measurement and standards can have on transmission resources (e.g., measurement and standards may increase existing system capacity by X percent or by Z GW-miles)?

System Planning and Operations (continued)

Increased Number of Market Players and the Impact on Power Reliability and Quality Issues

Will the increased number of power generation and ancillary service providers affect system reliability?

If so, how will reliability potentially be affected?

- increased frequency of outage?
- increased scope (number of customers) of outages?
- increased duration of outages?
- other impact metrics?

What will be the primary source of reliability problems?

- For example, will distributed generation be the main source of reliability problems?
- Other restructuring factors?

What role can measurement and standards play in maintaining reliability?

Will the increased number of power generation and ancillary service providers affect power quality?

If so, how will power quality be affected?

- Increase in the frequency of power disturbances such as transients, overvoltage (swell), undervoltage (sag), noise harmonics, or outages
- Will power quality problems effect both end users and power generators?

What role can measurement and standards play in maintaining power quality?

Market Functions

In general, what are the major technological issues that need to be addressed to implement wholesale and retail markets for electric power?

What are the potential impacts of inefficient markets?

For example,

- could the inability to measure the "cost causality" of the bulk power transmission systems limit the potential efficiency gains from restructuring?
- could market price structures that do not send proper incentives affect the efficiency, reliability, or power quality of the system?

Wholesale Market Transactions—Bulk Transmission

What measurements and standards are needed to support efficient pricing of bulk transmission? In which areas will these measurement and standards have the greatest potential impact?

For example,

- supporting measurement and data transmission for tracking transmission use?
- supporting cost causality models of bulk power transmission?
- supporting other needs for efficient pricing of bulk power transmission?

What are the economic benefits of meeting these needs?

For example,

- could efficient transmission pricing lead to decreased demand (GW miles) of transmission services for the same level of end-use power consumption?
- could efficient transmission pricing lead to an increase level of market transactions?

Wholesale Market Transactions—Generation

What measurement and standards are needed to measure the value of service provided by generator and ancillary service providers? In which areas will these measurement and standards have the greatest potential impact?

For example,

- verifying that generators meet contractual obligations?
- measuring generators' impact on system reliability and power quality?
- measuring value of services supplied by ancillary service providers?

Market Functions (continued)

What are the economic benefits of meeting these needs?

For example,

- improved quality services provided by generators and ancillary service providers?
- decreased transactions costs, such as less expensive meters or fewer legal disputes?

Retail Market Transactions

What measurement and standards are needed to support metering and billing for retail services? In which areas will these measurement and standards have the greatest potential impact?

For example,

- facilitating electronic data interfaces (EDI) between meters and systems of different equipment manufacturers?
- developing protocols for EDI to distribute customer and system information to the increasing number of market players involved in account reconciliation?

What are the economic benefits of meeting these needs?

For example,

- decreased cost of metering and billing activities?
- improved accurate billing?
- availability of pricing incentives for demand-side management?
- fewer billing errors
- identifying and decreasing cross-subsidization between customer groups?

We thank you in advance for participating in this study.

Measurement Technologies and Standards Important to Deregulating the Electricity Industry

Thank you for agreeing to participate in The National Institute of Standards and Technology's (NIST's) study on measurement and standards issues important to the electric power industry. Below is a brief introduction to the study and its objectives, followed by a short questionnaire.

Background

NIST recently commissioned Research Triangle Institute (RTI) to study technology trends in the generation, transmission, and distribution sectors. As part of this analysis, RTI is assessing measurement and standards needs identified by power industry experts and investigating the economic impact of meeting (or not meeting) these needs.

The results of this study will be made available in a NIST publication and will be presented during a NIST-sponsored national conference on "New Challenges for Measurements and Standards in a Deregulated Electric Power Industry," which will be held December 6-8, 1999.

Questionnaire

The purpose of this questionnaire is to obtain information to assist, in quantifying the economic impact of meeting (or not meeting) measurement and standards needs of a restructured electric power industry.

I'm sure you will agree that this is an ambitious task and that any impact estimates that are developed as part of this study will be the subject of great scrutiny and debate. It is not our intent to develop a definitive estimate of the value of measurement and standards. In contrast, we are hoping to develop a range of potential impacts associated with measurement and standards that reflect the large uncertainty in the evolution of the industry structure and in future technology developments.

We understand that providing a numerical approximation (guess) of the impacts of measurement and standards is very difficult. For this reason, we encourage you to provide ranges as shown in the examples. In addition, in many cases your first response will probably be "it depends" on how the future of the industry unfolds. At the end of the questionnaire there is space for you to provide specific caveats or assumptions associated with your responses.

The impact categories listed on the next few pages were identified during interviews with utility system planners, regulators, equipment manufacturers, academics, and organizations such as EPRI, FERC, and regional ISOs. We encourage you to include additional categories for which you feel measurement and standards will be important.

We view this questionnaire as eliciting individual opinions of industry experts. Responses will not be interpreted as representing official positions of your company or organization. In addition, any information provided will be aggregated, and only average responses will be included in the presentation and report. All individual responses will remain strictly confidential, and no individuals will be identified in the report.

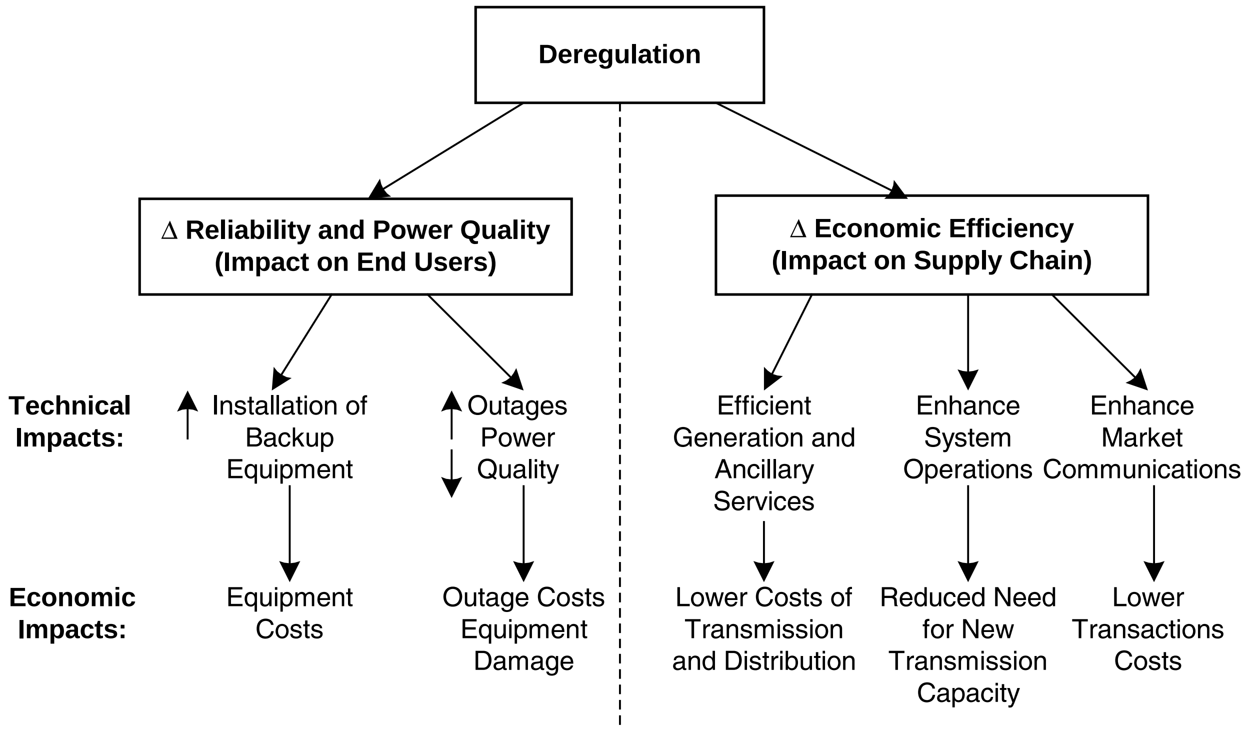
Once again, we thank you for your assistance. If you have any questions or comments, please feel free to call Steve Johnston at 919 541-5935

Please return your questionnaire to Ryan Avent by fax at 919-541-6683 or by e-mail to avent@rti.org.

Once again, thank you for your participation.

IMPACT OF DEREGULATION

Wholesale and retail deregulation has the potential to affect both the economic efficiency of the electric power system and the reliability and power quality of electric power to end users. Several examples are shown in the tree diagram below.



Please fill in the blanks below to indicate which areas you think will be affected by deregulation and provide your best guess (or range) of the potential size of the impact. For example,

- Deregulation may lead to a $-X_1$ to $-X_2$% change in the average cost of generation, and/or
- Deregulation may lead to a $+Z_1$ to $+Z_2$% change in transmission system monitoring expenditures, and/or
- Deregulation may lead to 0% change in the frequency of outages.

Impact of Deregulation (continued)

Reliability and Power Quality	**Economic Efficiency**
Deregulation may lead to a:	*Deregulation may lead to a:*
____ % change in the frequency of outages (greater than one second)	____ % change in the average cost of generation
____ % change in the average duration of outages	____ % change in the average cost of ancillary services
____ % change in the average number of end users affected during an outage event	____ % change in required transmission capacity, or the need for an additional _____ GW miles in transmission assets
____ % change in power quality events, such as transients, swells, sags, noise, harmonics	____ % change in system monitoring and communications costs
____ % change in equipment expenditures to provide backup for outages	____ % change in metering equipment expenditures
____ % change in equipment expenditures to compensate for power quality problems	____ % change in market transaction costs (such as billing, writing contracts, dispute resolution)
	____ % change in operating metering systems, such as installation, calibration service calls
	____ % change in the cost of usage data transfer, aggregation, and analysis to support market transaction
	____ % change peak demand reductions from demand-side programs, or ____ MW change in curtailment load programs
Other changes ____________________ ____________________ ____________________ ____________________	Other changes ____________________ ____________________ ____________________ ____________________

Comments/qualifiers/caveats for impacts provided above:

____

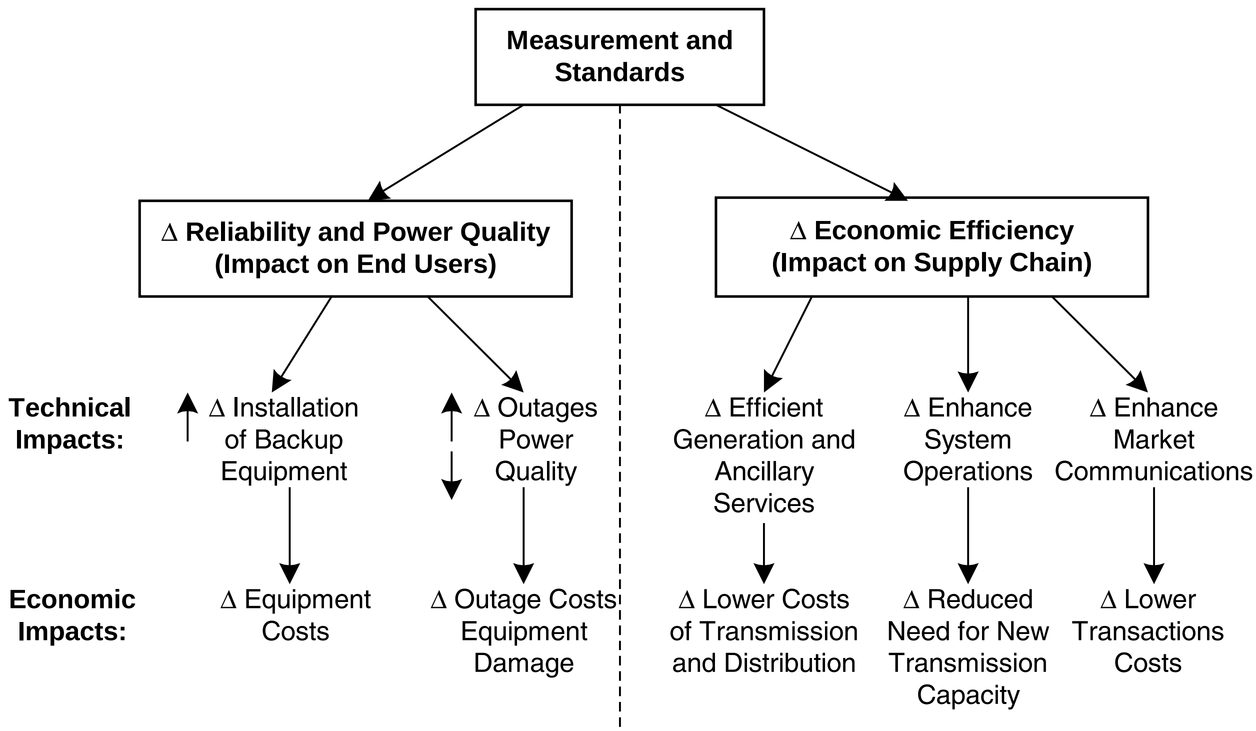
____

____

____

IMPACT OF MEASUREMENT AND STANDARDS

Measurement and standards will play an important role in determining the eventual impact wholesale and retail deregulation has on economic efficiency, power reliability, and power quality. Several examples are shown in the tree diagram below.



Please use the blanks below to indicate the areas where you think measurement and standards will have the greatest impact by indicating how your impact estimates provided above would change if proper measurement and standards were ***not*** available in the future.

For example,

- Without proper measurement and standards, the change in the average cost of generation would not be $-X_1$ to $-X_2$% (as indicated above), but would only be $-Y_1$ to $-Y_2$% (Y to be filled in on next page) and/or
- Without proper measurement and standards, the change in transmission system monitoring expenditures would not be $+Z_1$ to $+Z_2$% (as indicated above), but would only be $+W_1$ to $+W_2$% (W to be filled in on next page) and/or
- Without proper measurement and standards, the change in outages would not be 0% (as indicated above), but would actually be __V__% (V to be filled in on next page).

Impact of Measurement and Standards (continued)

Reliability and Power Quality	**Economic Efficiency**
Without proper measurement and standards deregulation may instead lead to a:	*Without proper measurement and standards deregulation may instead lead to a:*
____ % change in the frequency of outages (greater than one second)	____ % change in the average cost of generation
____ % change in the average duration of outages	____ % change in the average cost of ancillary services
____ % change in the average number of end users affected during an outage event	____ % change in required transmission capacity, or the need for an additional _____ GW miles in transmission assets
____ % change in power quality events, such as transients, swells, sags, noise, harmonics	____ % change in system monitoring and communications costs
____ % change in equipment expenditures to provide backup for outages	____ % change in metering equipment expenditures
____ % change in equipment expenditures to compensate for power quality problems	____ % change in market transaction costs (such as billing, writing contracts, dispute resolution)
	____ % change in operating metering systems, such as installation, calibration service calls
	____ % change in the cost of usage data transfer, aggregation, and analysis to support market transaction
	____ % change peak demand reductions from demand-side programs, or ____ MW change in curtailment load programs
Other changes ____________________ ____________________ ____________________ ____________________	Other changes ____________________ ____________________ ____________________ ____________________

Comments/qualifiers/caveats for impacts provided above:

____

____

____

____

Thank you for your participation.

Appendix D:
Interview Responses

D.1 IOU SYSTEM PLANNERS

Potential Benefits Associated with Deregulation

- Systems will operate closer to their capacity.
- Introduction of a market will optimize energy supply.
- Price signals will become clearer.
- Restructuring will bring improved consumer choice.
- Good technologies will be incorporated sooner, while bad technologies will be ignored or phased out faster.
- Prices should fall.
- Power will be able to flow from surplus areas to shortage areas.
- Reserve sharing may lower the cost of ancillary services.

Potential Costs Associated with Deregulation

- Engineering efficiency will fall, at least in the short run, due to subjecting systems, especially those involved with transmission, to strains for which they were not intended.
- Ancillary services costs will increase, but this will mainly result from the need to install improved metering instruments.
- Costs will increase due to increased metering requirements associated with determining energy imbalances.
- Data management systems will have to be greatly improved, which will increase costs.
- New transmission will not be built, because no one will invest in lines they will have to share.

Measurement and Standards Needs Associated with System Planning and Operations

- Standards will be needed to determine thermal limits for transmission lines.
- Standards will be needed not just for design issues but also for system performance.
- Measurement is needed to determine how close to capacity transmission systems are running.
- Standards need to be set for a measure of system reliability.
- Standards are needed for communication protocols and technology/methods for data collection.
- The industry needs a standard number for loading state to alert operators to approaching limits.

- Communication and measurement need to improve to help facilitate interaction between newly separated gencos and transcos.
- Measurement will have to increase dramatically to get away from load-profiling.
- Thermal monitoring systems need to be installed cross-country.
- Better measurement and monitoring systems will be required to protect investments from damage due to improper use.
- Measurement will need to be improved at stations and substations to allow incorporation of dispersed generation assets.
- Standards may be needed to determine an appropriate level of meter accuracy and voltmeter accuracy.
- Standards may be needed for power quality.
- Distributed generation will require standards to be set for frequency.

Measurement and Standards Needs with Wholesale Market Transactions

- Ancillary services need to be defined.
- Faster/cheaper metering and communications are needed to bring smaller energy providers into the fold.
- Standards need to be established to ensure contractual compliance.
- Standards need to be established for performance of generation equipment and for providers of metering services.
- Standards will be needed anywhere different systems interact.
- Standards will be needed to ensure system security.
- Standards will be needed across the board, from compliance/enforcement mechanisms to communication systems.
- There should be standard interface requirements.
- Increased transactions will necessitate improved communication systems.
- Standards will be needed to determine the value of an interface relative to congestion.

Measurement and Standards Needs with Retail Market Functions

- Metering will ultimately have to improve at a retail level.

D.2 RTO/POOL OPERATORS

Potential Benefits Associated with Deregulation

- Separated ancillary services may lead to more efficient service pricing and, thus, lower ancillary costs.
- Deregulation-fueled competition may lead to a reduction in high-cost generation.
- Open access will cause more energy to be readily available and transferable, reducing shortages and emergencies.
- Restructuring should reduce the average cost of generation.
- Low-cost suppliers of power will enter the market.
- Improved price signals after restructuring will improve the efficiency of consumer usage.

Potential Costs Associated with Deregulation

- Original set-up costs of ISOs or equivalent could be quite high.
- Running an efficient power market will require real-time metering and billing, which will be very expensive to develop.
- More complex transmission systems will require improved monitoring, metering, and data management technologies, which will all add to cost.

Measurement and Standards Needs Associated with System Planning and Operations

- Interface numbers will increase, which will require increased measurement to manage transmission.
- Measurement improvements will be needed to squeeze more capacity out of existing lines.
- Communication systems will have to be improved, and systems will have to be able to read more than one protocol, which may require standards to be set.
- Measurement will need to see improvements to deal with shifts in generation and transmission locations.
- Measurement and standards are vital to alleviating transmission constraints.
- Diffused generation will require standards to be set to maintain reliability.
- ISOs and RTOs can help deal with transmission constraints but require metering and monitoring improvements.
- Improved metering will improve consumer decisionmaking, which will help alleviate system congestion.

D.3 EQUIPMENT MANUFACTURERS

Potential Benefits Associated with Deregulation

- Larger users will obtain lower prices through their ability to negotiate.
- Smaller users will have more energy options.
- Outsourcing of certain tasks (metering) will lower costs.
- Metering will improve.
- More accurate metering will affect demand-side behavior in a positive way.
- Improved metering will assign system-threatening loads the appropriate costs.

Potential Costs Associated with Deregulation

- Efficiency costs could be a long time coming as they will originally be offset by necessary measurement and monitoring improvements.

Measurement and Standards Needs Associated with System Planning and Operations

- Monitoring of the transmission system must increase.
- Generation and transmission need to be metered more heavily.
- Interconnection requirements need to be established.
- IT standards will need to be developed for system operation and maintenance.
- Monitoring will need to improve as ancillary services are unbundled.

Measurement and Standards Needs with Wholesale Market Transactions

- Measurement will need to improve to capture benefits of long-distance transactions.
- Measurement or standards or both need to improve to improve accountability for power generation and reliability.

Measurement and Standards Need with Retail Market Functions

- Metering will need to be vastly improved to take advantage of choice offerings.
- Standard meter protocols should be developed and soon to facilitate manufacture of appropriate meters.

- Without standard meters, customers may have to change meters when they change providers.
- Standards may be important in establishing what security is needed in each stage of the distribution process.
- A standard modular meter model could greatly improve efficiency and customer choice.

D.4 REGULATORS

Potential Benefits Associated with Deregulation

- Competition will increase under deregulation.
- Electricity prices will fall.
- Inefficient generators will be forced to shut down.
- Ancillary service costs will decrease; this will be monitored by regulators to ensure fairness.

Measurement and Standards Needs Associated with System Planning and Operations

- The industry must develop improved data collection systems and improved tagging systems.
- Monitoring will need to improve from both producers and regulators to guarantee power quality and reliability.

Measurement and Standards Needs with Wholesale Market Transactions

- Standards need to be developed on compliance mechanisms.
- Measurements need to be uniform.
- Communication will need to improve greatly.
- Standard security measures will need to be examined.

D.5 ACADEMIC

Potential Benefits Associated with Deregulation

- Large consumers will experience considerable benefits.
- In the long run, all consumers should see price reductions.
- Real-time-pricing will bring efficiency benefits.
- Customers can modify their behavior to reduce costs.
- Efficient businesses will succeed while inefficient businesses will go out of business.
- Consumers will enjoy choice between service, price, etc.
- Better measurement will lower transaction costs.

Potential Costs Associated with Deregulation

- Equipment/power quality may fall as utilities attempt to keep prices low.
- Tendency to gravitate toward cheaper instruments may lock in cheap technology.
- With real-time-pricing, retailers will be able to more easily price-discriminate.

Measurement and Standards Needs Associated with System Planning and Operations

- ISOs will require vast amounts of information and, thus, great IT improvements.
- Large increases in the distance power must travel will require investments in measurement and monitoring technologies.

Measurement and Standards Needs with Wholesale Market Transactions

- Standards will become vital at points of system interconnection and between unrelated communication systems.
- Measurement and standards must improve to confirm compliance with contractual obligations.

Appendix E: Calculation of Event Cost Metrics

This appendix contains a description of the estimation procedures and assumptions we used to develop the event cost estimates presented in Table 5-4.

E.1 SYSTEM OPERATIONS

E.1.1 Generation Production Costs

In 1997, the total estimated cost of electricity generation was approximately $100 billion. This estimate includes fuel and other generating costs incurred by both publicly owned (POUs) and investor-owned utilities (IOUs) and the cost of purchases from nonutility generators. These numbers do not include non-utility electricity sales directly to customers, which will likely remain unaffected by deregulation. These data were obtained from the Energy Information Administration's (EIA's) Electric Power Annual 1997.

E.1.2 Ancillary Services

The provision of ancillary services is estimated to cost industry $12 billion a year (Hirst and Kirby, 1998). This estimate includes services such as regulation, spinning reserve, supplemental reserve, load following, and backup supply.

E.1.3 Transmission Assets

New Transmission Lines

The weighted average cost per mile of new overhead bulk transmission lines (voltage greater than 138 kV) used in this study is approximately $0.4 million per mile (see Table E-1). Arthur Fuldner (1996) of the EIA and the Progress and Freedom Foundation (PFF) developed typical construction costs per mile for lines ranging between 138 kV and 765 kV. The costs were weighted by the number of miles nationally for each line voltage and then averaged to determine a typical replacement cost. This estimate is likely to be conservative because it does not include expenditures for right of way or legal costs.

Table E-1. Cost of Adding New Transmission Lines and Restringing Existing Corridors
The replacement value of the U.S. bulk power transmission system is more than $100 billion.

Voltage (kV)	Circuit Miles in U.S.	Replacement Cost per Circuit Mile	Weighted Replacement Cost per Circuit Mile	Replacement Value of Existing Transmission System	Restringing Cost per Circuit Mile	Weighted Restringing Cost per Circuit Mile
138	73,186	281,287		20,586,270,382	132,742	
161	25,227	329,483		8,311,867,641	155,486	
230	69,598	477,500		33,233,045,000	193,333	
345	54,593	477,500		26,068,157,500	193,333	
500	27,960	477,500		13,350,900,000	193,333	
765	3,142	477,500		1,500,305,000	193,333	
Totals	253,706		406,181	103,050,545,523		172,091

Sources: Fuldner, Arthur. 1996. *Upgrading Transmission Capacity for Wholesale Electric Trade*. Washington, DC: Energy Information Administration.

Progress & Freedom Foundation. 1999. The Replacement Cost of the U.S. Investor Owned Utilities' Transmission System. <http://pff.org/energy/appendix.html>. As obtained on November 10, 1999.

Edison Electric Institute. 1998. *Statistical Yearbook of the Electric Utility Industry, 1997*. Washington, DC: Edison Electric Institute.

Other estimates for new bulk transmission lines are also in the neighborhood of half a million dollars per mile. Douglas (1992) estimated the cost of new bulk transmission lines to be approximately $477,500 per mile.

Restringing Transmission Lines

The weighted average cost of restringing existing corridors is $172,091 per mile (see Table E-1). The same weights and methodology were used to determine the weighted average costs of new corridors were also used to determine those for restringing.

The Cost of Increased Transmission Capacity

The exisitng power system has approximately 250,000 miles of bulk transmission lines. Thus, a 1 percent increase represents approximately 2,500 line-miles. Assuming that upgrades to the system would be achieved by a combination of new corridors and restringing (50-50 weight), the average cost of new capacity would be approximately $324,800 per mile. Thus, a 1 percent increase in the bulk transmission system is estimated to cost over $812 million.

Discounting over 20 years using a 7 percent discount rate yields an annualized cost of $76.6 million to increase the system by 1 percent, or restated, $7,660 million to expand the system by 100 percent.

E.1.4 Outage Costs

According to the Electric Power Research Institute (1996), unplanned power outages cost U.S. businesses an estimated $29 billion each year. This figure accounts for the losses in commercial and industrial productivity that occur during transmission and distribution power outages. In addition, according to *Power Quality Assurance* (PQA), a bimonthly journal for power quality professionals, U.S. industry expenditures on back-up generation equipment are approximately $1 billion a year.

E.1.5 Expenditures on Power Cleaning Equipment

Expenditures on protective power cleaning equipment are approximately $4.3 billion (*PQA*, 1999). Information was not available on the cost of power quality problems in terms of equipment damage and lost productivity. Thus, the estimate of $4.3 billion per year is likely to significantly underestimate the annual cost of power quality problems in the U.S.

E.2 MARKET OPERATIONS

E.2.1 Metering Costs

The U.S. power industry spends approximately $280 million dollars on metering equipment annually (Electrical World, 1998). IOUs spend an additional $613 million per year on meter operations and maintenance. Metering operations and maintenance costs include installation, calibration, service calls, and wireless communications systems (EIA, 1997). Data for POUs were not available at this level of detail; therefore, $613 million per year is a conservative estimate of metering operations.

E.2.2 Data Management and Transactions Costs

Data management costs for IOUs are approximately $2 billion a year (EIA, 1997). Utilities collect, process, and maintain large quantities of data. The $2 billion per year estimate includes management and maintenance costs and transactions costs, such as contracts, billing, and dispute settlement. Data for POUs were not readily available at this level of detail.