The Future of the Electric Grid

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Foreword and Acknowledgments

For well over a century, electricity has made vital contributions to the growth of the U.S. economy and the quality of American life. The U.S. electric grid is a remarkable achievement, linking electric generation units reliably and efficiently to millions of residential, commercial, and industrial users of electricity through more than six million miles of lines and associated equipment that are designed and managed by more than 3,000 organizations, many of which are in turn regulated by both federal and state agencies. While this remarkable system of systems will continue to serve us well, it will face serious challenges in the next two decades that will demand the intelligent use of new technologies and the adoption of more appropriate regulatory policies.

This report aims to provide a comprehensive, objective portrait of the U.S. electric grid and the challenges and opportunities it is likely to face over the next two decades. It also highlights a number of areas in which policy changes, focused research and demonstration, and the collection and sharing of important data can facilitate meeting the challenges and seizing the opportunities that the grid will face.

This study is the sixth in the MIT Energy Initiative's "*Future of*" series. Its predecessors have shed light on a range of complex and important issues involving energy and the environment. While the previous studies have focused on particular technologies and energy supply, our study of the grid necessarily considers many technologies and multiple overlapping physical and regulatory systems. Because of this breadth, our efforts were focused on integrating and evaluating existing knowledge rather than performing original research and analysis. In addition, this study's predecessors focused on implications of national policies limiting carbon emissions, while we do not make assumptions regarding future carbon policy initiatives. Instead, we mainly consider the implications of a set of ongoing trends and existing policies.

We anticipate this report will be of value to a wide range of decision makers in industry and government as they guide the grid's continuing evolution. We have attempted to provide thorough discussions of key topics to serve as references, to support our findings and recommendations, and to meet the needs of what we expect will be a diverse audience in terms of interest and expertise. Also, for those less familiar with the industry, we include appendices on the grid's history and technology. Chapter 1 provides an overview of the status of the grid, the challenges and opportunities it will face, and our major recommendations. To facilitate selective reading, detailed descriptions of the contents of each section in Chapters 2–9 are provided in each chapter's introduction, and recommendations are collected and briefly discussed in each chapter's final section.

The MIT *Future of the Electric Grid Study* gratefully acknowledges the sponsors of this study: ABB Group, American Electric Power, Bechtel Foundation, Larry Birenbaum, Cisco Systems, Exelon Corporation, General Electric Company, Iberdrola S.A., Microsoft Corporation, National Institute of Standards and Technology, and Southern California Edison. In addition to providing financial support, many of our corporate and government sponsors gave us access to staff members who provided frequent and detailed information about technical and policy issues. We are very grateful for this cooperation.

The Advisory Committee members dedicated a significant amount of their time to participate in multiple meetings, read and comment on several early drafts of the report, and make available experts from their own organizations to answer our questions and contribute to the content of the report. We would especially like to acknowledge the efficient conduct of Advisory Committee meetings under the able and experienced direction of Senator J. Bennett Johnston, Chair.

In addition to all of the valuable contributions from the sponsors, the Advisory Committee, and other members of their respective organizations, research on this project also benefited from individual conversations with Lauren Azar, Andrew Bochman, Paul Centolella, Matt Dinsmore, Joseph Eto, Emily Fisher, Richard O'Neill, Arun Phadke, a number of individuals in the Brattle Group and National Grid, and countless others who we interacted with at conferences and industry events.

This study was initiated and performed within the MIT Energy Initiative (MITei). The Director of MITei, Professor Ernest J. Moniz, selected the Co-Chairs of the study, helped identify members of the Advisory Committee, and helped engage the study sponsors. MITei staff provided administrative and financial management assistance to this project. In addition, we would like to acknowledge the important contributions of Melanie Kenderdine, Joseph Hezir, Rebecca Marshall-Howarth, Patricia Connell, Natalie Liang, and Justin Daniels.

Finally, we would like to thank Sarah Aldy for editing this document and maintaining her patience with our team through many complicated iterations. Any errors in the final document are the responsibility of the study group and not the editor or anyone else.

The final report represents the opinions of the study group, which is solely responsible for its content. The advisory committee and sponsors are not responsible for, and do not necessarily endorse, the findings and recommendations contained within this report.

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Abstract

The U.S. electric grid is a vast physical and human network connecting thousands of electricity generators to millions of consumers—a linked system of public and private enterprises operating within a web of government institutions: federal, regional, state, and municipal. The grid will face a number of serious challenges over the next two decades, while new technologies also present valuable opportunities for meeting these challenges. A failure to realize these opportunities or meet these challenges could result in degraded reliability, significantly increased costs, and a failure to achieve several public policy goals.

This report, the fifth in the MIT Energy Initiative's *Future of* series, aims to provide a comprehensive, objective portrait of the U.S. electric grid and the identification and analysis of areas in which intelligent policy changes, focused research, and data development and sharing can contribute to meeting the challenges the grid is facing. It reflects a focus on integrating and evaluating existing knowledge rather than performing original research. We hope it will be of value to decision makers in industry and in all levels of government as they guide the grid's necessary evolution.

One of the most important emerging challenges facing the grid is the need to incorporate more renewable generation in response to policy initiatives at both state and federal levels. Much of this capacity will rely on either solar or wind power and will accordingly produce output that is variable over time and imperfectly predictable, making it harder for system operators to match generation and load at every instant. Utilizing the best resource locations will require many renewable generators to be located far from existing load centers and will thus necessitate expansion of the transmission system, often via unusually long transmission lines. Current planning processes, cost-allocation procedures, and siting regimes will need to be changed to facilitate this expansion. In addition, increased penetration of renewable distributed generation will pose challenges for the design and operation of distribution systems, and may raise costs for many consumers.

Increased penetration of electric vehicles and other ongoing changes in electricity demand will, if measures are not taken, increase the ratio of peak to average demand and thus further reduce capacity utilization and raise rates. Changes in retail pricing policies, enabled by new metering technology, could help to mitigate this problem. Increased penetration of distributed generation will pose challenges for the design and operation of distribution systems. New regulatory approaches may be required to encourage the adoption of innovative network technologies.

Opportunities for improving the functioning and reliability of the grid arise from technological developments in sensing, communications, control, and power electronics. These technologies can enhance efficiency and reliability, increase capacity utilization, enable more rapid response to remediate contingencies, and increase flexibility in controlling power flows on transmission lines. If properly deployed and accompanied by appropriate policies, they can deal effectively with some of the challenges described above. They can facilitate the integration of large volumes of renewable and distributed generation, provide greater visibility of the instantaneous state of the grid, and make possible the engagement of demand as a resource.

All these new technologies involve increased data communication, and thus they raise important issues of standardization, cybersecurity, and privacy.

Decision makers in government and industry have taken important actions in recent years to guide the evolution of the U.S. electric power system to address the challenges and opportunities noted above. Yet the diversity of ownership and regulatory structures within the U.S. grid complicates policy-making, and a number of institutional, regulatory, and technical impediments remain that require action. Our main recommendations can be briefly summarized as follows:

- To facilitate the integration of remote renewables, the Federal Energy Regulatory Commission should be granted enhanced authority to site major transmission facilities that cross state lines.

- To cope more effectively with increasing cybersecurity threats, a single federal agency should be given responsibility for cybersecurity preparedness, response, and recovery across the entire electric power sector, including both bulk power and distribution systems.

- To improve the grid's efficiency and lower rates, utilities with advanced metering technology should begin a transition to pricing regimes in which customers pay rates that reflect the time-varying costs of supplying power.

- To improve utilities' and their customers' incentives related to distributed generation and energy conservation, utilities should recover fixed network costs through customer charges that do not vary with the volume of electricity consumption.

- To make effective use of new technologies, the electric power industry should fund increased research and development in several key areas, including computational tools for bulk power system operation, methods for wide-area transmission planning, procedures for response to and recovery from cyberattacks, and models of consumer response to real-time pricing.

- To improve decision making in an increasingly complex and dynamic environment, more detailed data should be compiled and shared, including information on the bulk power system, comprehensive results from "smart grid" demonstration projects, and standardized metrics of utility cost and performance.

Chapter 1: Challenges, Opportunities, and Major Recommendations

This chapter gives an overview of the study and introduces our major findings and recommendations. Section 1.1 provides a brief description of the grid's current structure and performance, which serve as initial conditions for our analysis. (Readers may consult Appendix A for a brief history of the U.S. grid and Appendix B for additional information on the technical operation of electric power systems.)

Section 1.2 then outlines challenges and opportunities that the grid will confront over the next two decades: incorporating variable energy sources like wind and solar; handling the charging of electric vehicles; adjusting distribution systems to accommodate small-scale, distributed electric generators; meeting emerging workforce needs; making the best use of new technologies to ensure reliability and efficiency under changing conditions; and responding to issues presented by the vast increase of data communications within the grid. Along the way some of the study's key findings are summarized.

Section 1.3 then presents the major recommendations that flow from these concerns, organized by area of industry and government policy response: the transmission system, the distribution system, cybersecurity and privacy, research and development, and the need for improved data development and sharing of information. Section 1.4 concludes with brief remarks about the level of urgency attached to these issues.

Hailed as the "supreme engineering achievement of the 20th century" by the National Academy of Engineering,[1] the U.S. electric power grid serves more than 143 million residential, commercial, and industrial customers[2] through more than 6 million miles of transmission and distribution lines owned by more than 3,000 highly diverse investor-owned, government-owned, and cooperative enterprises.[3] In 2009, electric generation consumed 41% of the nation's primary energy—up from 14% in 1949—underscoring the great and growing national importance of the grid's efficiency and reliability.[4]

The electric power system is composed of four interacting physical elements: energy generation, high-voltage transmission, lower-voltage distribution, and energy consumption, or load. Two less tangible elements are also important: the operational systems that protect and control the physical elements, and the regulatory and governance structures that shape the system's evolution. The term "grid" as used in this report refers not only to the physical transmission and distribution systems that link generators to ultimate loads but also the associated operational, regulatory, and governance structures. Appendix A briefly summarizes the history of the U.S. grid.

This study considers the evolution of the U.S. electric grid over the next two decades—a period long enough to permit significant change but short enough to make it unlikely that unforeseen technologies will have significant impacts on the system.[i] Even though this is likely to be a period of slow growth in the U.S. demand for electricity by historical standards, public policies and a variety of technological and economic changes will alter

This study considers the evolution of the U.S. electric grid over the next two decades.

[i] An excellent brief overview of many of the issues considered in this report is provided by P. L. Joskow, "Creating a Smarter U.S. Electricity Grid," *Journal of Economic Perspectives*, forthcoming.

both the demand for and supply of electricity in challenging ways. If regulatory policies and the technologies employed in the grid do not change, it is likely to be difficult to maintain acceptable reliability and electric rates. Technologies exist that can meet these challenges effectively, but only if a number of regulatory policies are changed, necessary

The U.S. does not have a comprehensive national electricity policy, and regulatory regimes differ substantially among states.

research and development is performed, and important data are compiled and shared. Several features of electric power systems are fundamental to their structure and operation:

- It is generally not economically feasible to store electricity in bulk. The widespread deployment of new storage technologies and/or high penetrations of electric vehicles may someday change this, but these developments are unlikely before 2030.

- It follows that electric power systems must vary the supply of electricity to meet minute-to-minute changes in demand and in the output of variable energy sources such as wind and solar generators. Power systems must be built with enough capacity to meet expected peak demand with some excess capacity for safety.

- Electricity flows through many transmission paths from generators to customers, and individual flows cannot be controlled with precision.

- An electric grid is a natural monopoly; it would be prohibitively expensive to have multiple overlapping grids in any region.

- The need to maintain instantaneous balance of supply and demand, limits on transmission line capacities, and other features require central coordination of short-term system operations.[ii]

This chapter assumes essentially no additional knowledge of the workings of electric power systems, but some parts of later chapters may be hard to understand without more background. Readers who would like more background or encounter material they find difficult are urged to consult Appendix B.

1.1 TODAY'S ELECTRIC GRID

In natural gas, trucking, railroads, airlines, and telecommunications—industries with a history of deep and ongoing government involvement—federal policy was substantially reformed after 1970 to reflect market realities. In contrast, despite dramatic changes in the electric power sector, federal policies established in the 1930s and even earlier still play a central role in that sector. The federal government primarily has added new policies on top of old ones, unlike the European Union and many other nations that have adopted comprehensive new structures based on competitive wholesale and retail electricity markets and centrally managed networks subject to incentive-based regulation.

In this section, we first discuss the organization of the U.S. electric power industry. Even though state boundaries do not affect the flow of electricity and thus have no natural role in the design or operation of the electric power sector, state regulators retain considerable authority. The U.S. does not have a comprehensive national electricity policy, and regulatory regimes differ substantially among states.

[ii] As we discuss in later chapters, this last requirement has implications for many policies, including the role and design of competitive electricity markets.[5]

The result is substantial regional differences. Organized wholesale markets for power are central in some areas and nonexistent in others. Subsidies of various sorts for public and cooperative entities are important in some regions but not at all in others.

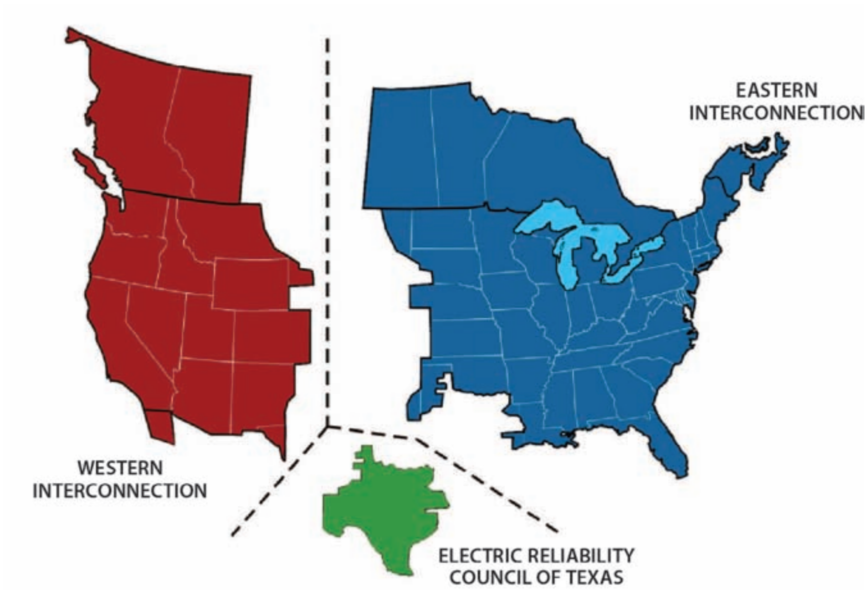
We then turn to a discussion of the industry's performance. The industry has done reasonably well relative to available international benchmarks, despite working within a policy regime not conducive to efficiency. Because the grid is currently functioning well, however, adequate support for fundamental policy reform may be unlikely to emerge in the near term. Thus for the most part we take today's policy regime as given, but, as Section 1.3 makes clear, we believe that some policy changes are necessary to prevent a deterioration of the grid's performance in light of emerging challenges.

Structure

At the highest level, the electric power system of the continental U.S. consists of three independently synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT). They are linked by only a few low-capacity direct current (dc) lines. These three grids, shown in Figure 1.1, account for 73%, 19%, and 8%, respectively, of U.S. electricity sales.[6]

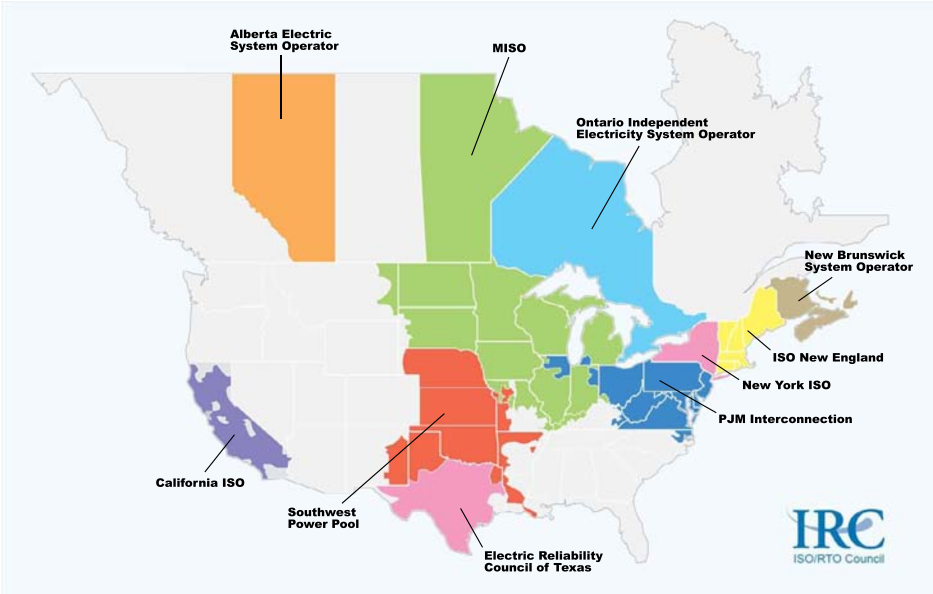
For a variety of reasons, discussion of which are beyond the scope of this study, organized wholesale markets do not exist in large parts of the nation, despite national policy supporting competitive wholesale markets with open,

Figure 1.1 Interconnections of the North American Electric Grid



Source: U.S. Department of Energy, http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/NERC_Interconnection_1A.pdf.

Figure 1.2 Regions with Organized Electricity Markets



Source: ISO/RTO Council, http://www.isorto.org. Copyright © ISO/RTO Council, all rights reserved.

non-discriminatory access to transmission systems (see Figure 1.2). Nonetheless, this policy has major implications for the transmission grid. Where it has been implemented, it has led to organized markets with important common elements.

Figure 1.2 shows the geographic scope of organized wholesale electricity markets, which are operated by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) that do not own generators or serve retail customers. These markets now cover two-thirds of the U.S. population and meet about two-thirds of U.S. demand. Box 1.1 provides an overview of the operation of these markets. In the Southeast, the traditional vertically integrated utility model is dominant, while in the West, particularly the Pacific Northwest, federal, municipally owned, and cooperative enterprises play an important role in the industry.

Within these broad areas are 107 so-called balancing authorities, shown in Figure 1.3, which are responsible for balancing the supply and demand for power in real time in specified areas. A glance at this map makes plain the strong influence of history. New York, New England, and Texas are each tightly integrated and have one balancing authority each, while Arkansas and Arizona each have eight and Florida has eleven. These differences plainly do not reflect differences in levels of supply or demand or in system complexity.

Physically, the U.S. electric grid currently consists of approximately 170,000 miles of high-voltage (above 200 kilovolts or kV) electric transmission lines and associated equipment,[7] and almost 6 million miles of lower-voltage distribution lines.[8] These include approximately 2,400 miles of 765 kV alternating current (ac) lines, the highest voltage lines in operation in the U.S., and more than 3,000 miles of 500 kV dc lines.[9] Several hundred entities currently own parts of the transmission or bulk power system.[10] Investor-owned utilities own about 66% of the system, and federal enterprises own 14%. The rest is divided among other publicly

BOX 1.1 WHOLESALE ELECTRICITY MARKETS

In those areas of the country with wholesale electricity markets, the ISO or RTO functions as both the operator of the system and the financial exchange for wholesale energy sales. Selling wholesale electric energy begins with a bidding process whereby generators offer an amount of energy (MWh) for sale during specific periods of the next day at a specific price ($/MWh). These offers are arranged by the ISO/RTO in ascending order called the "bid stack" and the generators are dispatched (told to generate) in this order until generation matches load. All the generators that are dispatched receive the same compensation called the "clearing price"—the offer of the last generator dispatched. The actual process is more complicated than this simple explanation, incorporating such parameters as the time required to start the generator, out-of-economic-order dispatch due to congestion or reliability concerns, and security constraints. Some base-load generators, such as nuclear plants, are costly to shut down or bring back on line, and will offer their energy at a price of zero to ensure that they are always dispatched. In some cases of very light load these generators may offer their energy at a negative price to guarantee they remain on line since the cost of stopping and starting outweighs the negative energy price. Consequently the cost of wholesale energy can swing wildly during a day—from near zero to near $1,000/MWh depending on load and the state of the generator fleet—though such a swing is not a usual occurrence. (For comparison, the average retail price of electricity in the U.S. is around $100/MWh.)

Some generators that use renewable energy—wind and solar mainly—have essentially zero variable costs, and the subsidies they receive for generation permit them to bid a negative price and still receive positive compensation for their energy. While zero bids from renewable generators reduce the market clearing price, they do not necessarily result in savings to society because the true cost of the renewable energy is the clearing price plus the subsidy.

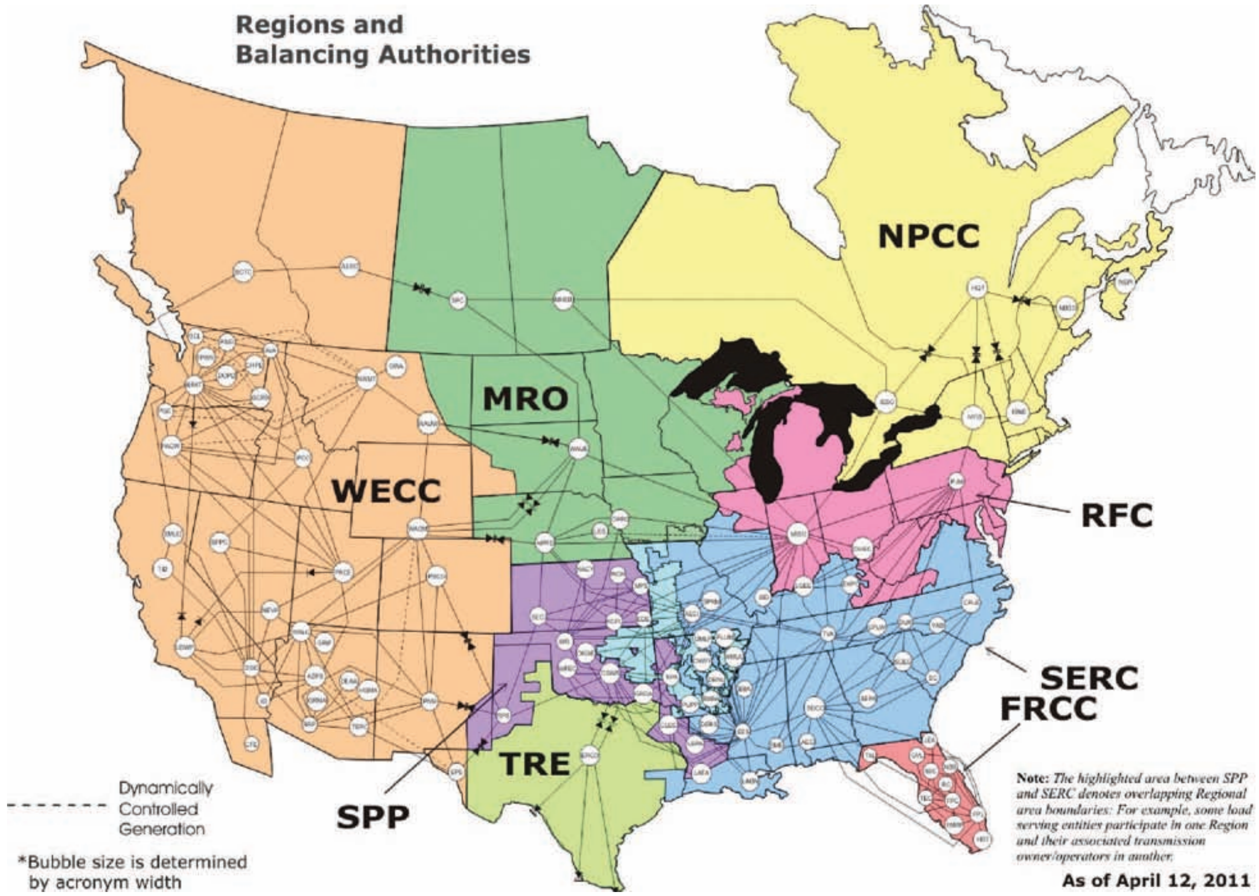
The majority of energy is traded through long-term bilateral contracts, where a buyer and a seller agree on a fixed price over a set period. Energy is still bought and sold in the real-time market as described above, but contracted sales are settled by a side transaction between the seller and buyer that accounts for the real-time price the parties paid and received. For a real-time price below the contract price the buyer pays the seller the difference, and for a price higher than the contract the seller pays the difference to the buyer.

In addition to energy, the electricity market has a number of other "products," the treatment of which varies from region to region. Among these are ancillary services, such as reserves of various types and capacity, which is designed to ensure that there is enough "iron in the ground" to meet future needs.

owned entities (7%), cooperatives (6%), independent transmission companies (4%), and others (3%). The U.S. Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electricity sales and transmission rates.

The U.S. grid serves about 125 million residential customers, 17.6 million commercial customers, and 775,000 industrial customers.[11] In aggregate, these categories of customers account for 37%, 36%, and 27% of electricity use, respectively. On average, commercial customers pay about 8% less per kilowatt hour (kWh) for electricity than residential customers, while industrial customers pay about 40% less, in part because these large customers can take power at higher voltages and incur lower delivery costs.

Figure 1.3 Balancing Authorities in the North American Electric Grid, 2011



Source: North American Electric Reliability Corporation, http://www.nerc.com/docs/oc/rs/BubbleMap_2011-04-12.jpg

Note: FRCC = Florida Reliability Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = ReliabilityFirst Corporation; SERC = SERC Reliability Corporation; SPP = Southwest Power Pool; TRE = Texas Regional Entity; WECC = Western Electricity Coordinating Council.

At the distribution level, about 3,200 organizations provide electricity to retail customers.[12] Nearly 2,200 are publicly owned—six by the federal government and the rest by states and municipalities—but they account for only 16% of electricity sold. Another 818 are cooperatives, which in aggregate account for 10.5% of kWh sales. In some areas of the country, particularly the Pacific Northwest, municipally owned and cooperative utilities benefit substantially from preferred access to low-cost power from federal projects. Only 242 distribution entities are investor owned, but they account for 66% of electricity sales. Their retail rates are regulated by state public utility commissions (PUCs). Finally, about 7.5% of retail sales are accounted for by retail power marketers that do not provide distribution services.

At the distribution level, about 3,200 organizations provide electricity to retail customers.

In some states (and in much of Europe), some customers can purchase electricity from competing retail suppliers, with the distribution utility remaining as the owner of the distribution network and the sole (regulated, cooperative, or government-owned) supplier of distribution services. Currently, there is little or no retail competition of this sort in 35 states. Fifteen states and the District of Columbia have active retail choice programs for residential electricity customers, but only in Texas do more than 15% of those customers purchase power from a competitive supplier.[13] In those same jurisdictions, commercial and industrial customers can choose among multiple suppliers, and in at least nine states and the District of Columbia more than 60% of large commercial and industrial customers have switched to competitive suppliers.[14]

At the generation level, in 2007, investor-owned utilities accounted for 42% of U.S. electricity generation.[15] Cooperatives and federal systems, including the Tennessee Valley Authority, each accounted for about 4%. Publicly owned systems organized at the state or municipal level accounted for another 8%. As a consequence of the structural reforms described in Appendix A, the remaining 42% was provided by independent power producers that do not serve retail customers. These enterprises mainly operated in regions with organized wholesale markets.

FINDING

As a result of the layering of historical policy decisions and the lack of a comprehensive, shared vision of system structure or function, the U.S. electric power system today operates under a fragmented and often inconsistent policy regime.

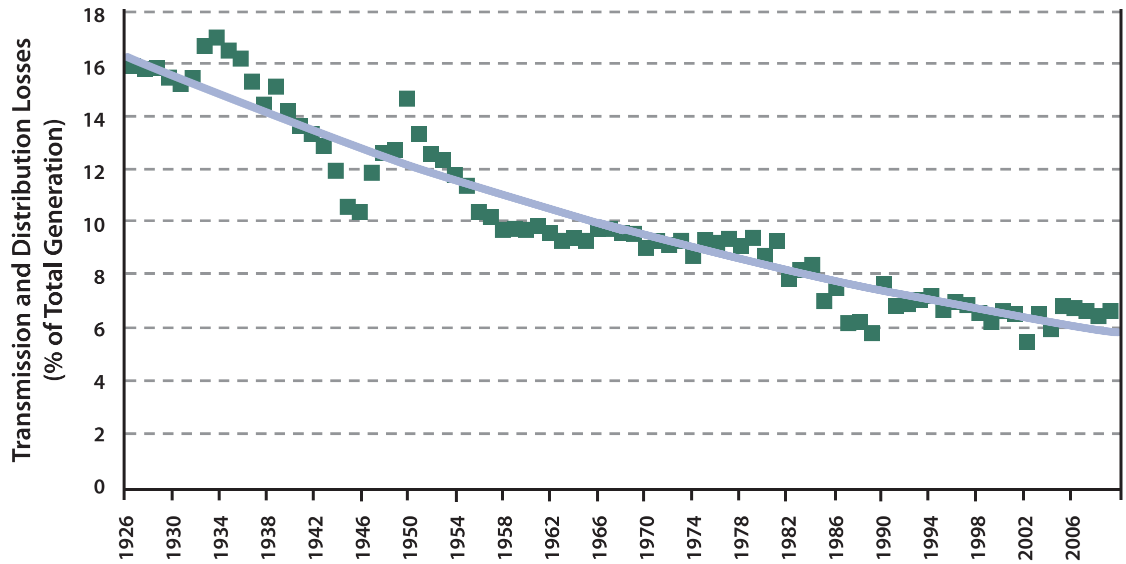
Performance

The U.S. grid is often referred to as "antiquated" or "broken" in the popular press and, occasionally, in technical publications.[16] However, assessing the performance of a system as complex as the U.S. electric grid is not a simple task. International comparisons and even comparisons within the U.S. are difficult because of differing geography, rates of growth, and definitions of performance measures. Systems that have grown more rapidly recently, for instance, on average will have newer equipment. Comparisons over time may reveal nothing more than the advance of technology driven by vendor R&D. Moreover, because there are diminishing returns to investing to increase efficiency and reliability, and perfection is unattainable at any cost, it is possible not just to underinvest but also to overinvest in these and other dimensions of performance.

An important measure of the performance of a transmission and distribution system is the fraction of energy generated that is lost due to heating of transmission and distribution lines and of other components. That fraction has fallen significantly over time in the U.S. As Figure 1.4 shows, losses in transmission and distribution decreased from more than 16% in the late 1920s to less than 7% today.[iii] This reflects investments in transmission and distribution systems, the development and deployment of more efficient transformers and other equipment, and transmission at higher voltages.

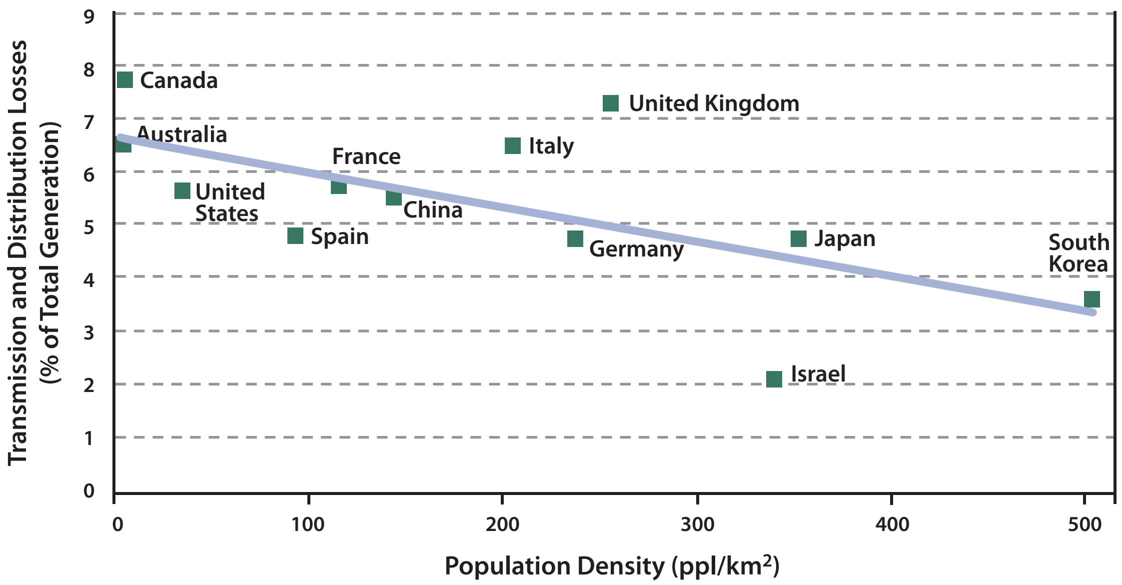
[iii] Losses are measured as the difference between energy generated and energy delivered to customers and thus in practice include losses due to theft. Theft is not considered to be important in the U.S. today, but it is significant in some other nations.

Figure 1.4 U.S. Transmission and Distribution Losses, 1926 to 2009



Source: Data for all years prior to 1943 were reported by the Edison Electric Institute. Losses for the years 1943 to 1951 were calculated using Edison Electric Institute data on generation, net imports, company use, producer use, and sales to customers. Company and producer use data were not reported during this time period, so the average of these quantities from 1941 and 1942 was used. Data for all years from 1951 to the present are from the U.S. Energy Information Administration Annual Energy Reviews.

Figure 1.5 Transmission and Distribution Losses for Selected Countries, 2008



Source: World Bank Development Indicators, http://data.worldbank.org/indicator.

Figure 1.5 indicates that U.S. losses are comparable to those of other wealthy countries with systems that also have substantial amounts of older equipment, but it cannot indicate whether U.S. losses are higher or lower than would be optimal. This figure also suggests that losses tend to decline somewhat with increasing population density, all else equal, as one would expect. At the same time, the data for Italy, where losses due to theft are said to be unusually high, and the United Kingdom, which has a relatively old grid, indicate that other factors may often be even more important than density.

Another important dimension of performance is reliability. Increases in transmission voltage and many other significant, less visible technological advances have contributed to the grid's reliability. Protective relaying enabled the detection and isolation of system faults, for instance, and high-speed reclosing circuit breakers and relaying allowed transmission lines to be reenergized after a fault automatically in less than a few seconds. Lightning arrestors allowed the effects of lightning strikes to be contained automatically.

As a result of these and other advances, customers in the U.S. can expect to experience between 1.5 and 2 power interruptions per year and between 2 and 8 hours without power.[17] This is on par with most European countries, where customers generally experience from less than 1 interruption per year to almost 3.[18] There is great variation between reliability in urban and rural areas, with power unavailable in U.S. urban areas averaging between 30 seconds and five minutes per year versus between nine hours and almost four days in rural areas.[19]

Data on outages are neither comprehensive nor consistent, however. Most outages occur within distribution systems, but only 35 U.S. states require utilities to report data on the impact of all outages on consumers, and reporting standards and practices differ.[20] It is accordingly impossible to make comprehensive comparisons across space or over time. In particular, the treatment of very short interruptions varies between states in the U.S. and between different countries, so counts of outages cannot be usefully compared. Minutes of outage per customer year is not much affected by these definitional differences, but data are nonetheless incomplete, and differences in national circumstances will clearly affect performance. At the bulk power level, data on major disturbances and unusual occurrences have been reported to the U.S. Department of Energy (DOE) since the 1970s and to the North American Electric Reliability Corporation (NERC), which has responsibility for the reliability of the bulk power system, since 1984. However, these data are not consistent, complete, or necessarily accurate, and they cannot reliably be used to assess changes in the reliability of the bulk power system over time.[21]

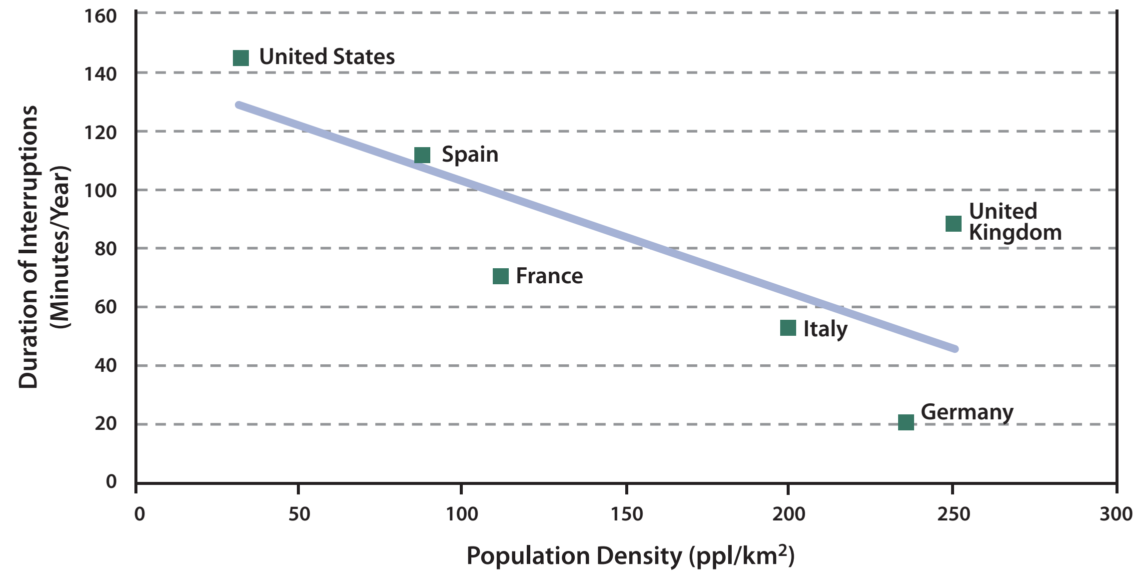
Data on outages are neither comprehensive nor consistent.

Figure 1.6 provides a comparison of minutes of outage per year in the U.S. and several European nations. Here, the U.S. is not out of line with other industrialized nations when we account for differences in population density (which correlates with the degree of urbanization). Such comparisons cannot reveal whether U.S. reliability is too low, too high, or optimal, given the benefits of reducing outages and the costs of doing so.

FINDING

Data are not available to quantitatively and accurately assess the reliability of the U.S. electric grid, particularly its changes over time. However, what data are available indicate the reliability of the U.S. grid is in line with that of other developed countries.

Figure 1.6 Average Duration of Interruptions for Selected Countries, 2006



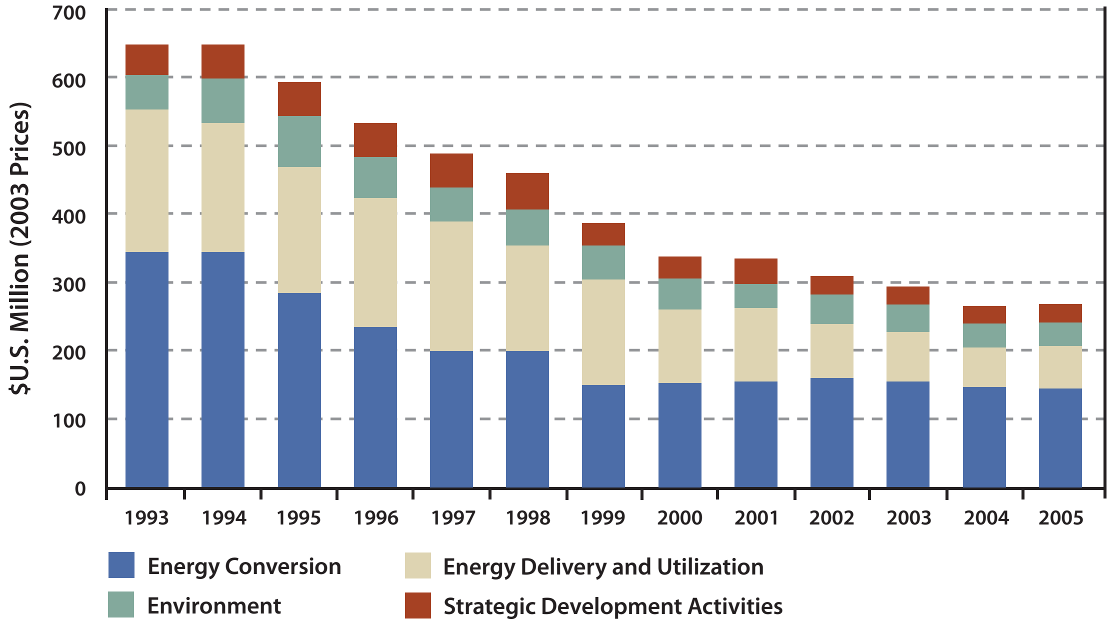
Source: United States Reliability Data: J.H. Eto and K.H. Lacommare, *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions* (Berkleley, CA: Lawrence Berkeley National Laboratory, 2008); European Reliability Data: Council of European Energy Regulators, *4th Benchmarking Report on Quality of Electricity Supply 2008* (Brussels, Belgium, 2008); Population Density: World Bank Development Indicators.

A final dimension of performance involves the use of new technology to increase productivity. The U.S. electric utility industry has historically devoted a very small fraction of its revenues to R&D, instead relying primarily on its suppliers for innovation. U.S. utilities have sometimes collaborated with vendors on R&D activities and have participated in collaborative research through the Electric Power Research Institute (EPRI), a nonprofit consortium founded in 1973. In recent years, however, utilities have shifted away from longer-term, collaborative projects and toward shorter-term proprietary efforts.[22] Moreover, investor-owned utilities, which account for almost all nonfederal utility R&D spending, reduced their R&D budgets beginning in the 1990s, spending on average less than 1% of their revenues on R&D. Figure 1.7 shows a steady decline in collaborative R&D spending through EPRI. The decrease in utility R&D funding reflects, in part, reluctance among utilities to incur—and regulators to approve—R&D expenditures as federal and state policies pursued more industry competition, particularly during the 1990s.

The U.S. electric utility industry has historically devoted a very small fraction of its revenues to R&D, instead relying primarily on its suppliers for innovation.

Productivity improvement in the electric power industry has historically been rapid relative to most other industries. This is reflected in a decline in real retail prices until the 1970s, as shown in Appendix A. The lack of a long-term decline in later years suggests that the difference may have decreased, but comparisons to other industries remain relatively favorable: the Bureau of Labor Statistics shows that over the 1987 to 2008 period, output per labor hour rose at an annual rate of 2.4% in power generation and supply, as compared to 2.1% in the overall private nonfarm business sector.[23]

Figure 1.7 Collaborative Research in the U.S. through the Electric Power Research Institute



Source: T. Jamasb and M. Pollitt, "Liberalisation and R&D in Network Industries: the Case of the Electricity Industry," *Research Policy* 37 (2008): 995–1008.

Data on broader measures of productivity do not seem to exist, and quantitative international comparisons do not seem possible. Anecdotal evidence from some vendors suggest that U.S. utilities, particularly those that are investor owned, have been less willing to deploy new technologies in recent years than their foreign counterparts. But without better data there is no way to verify, let alone quantify, this difference or its effects.

1.2 CHALLENGES AND OPPORTUNITIES

Even though the U.S. electric grid is not broken today, emerging challenges, if not met, could substantially degrade the system's reliability and efficiency over the next few decades. This section briefly introduces the main challenges the grid will face between now and 2030, the technologies that can be used to deal with them effectively, and important challenges posed by deployment of some of those technologies. The findings presented below are developed and supported in detail in later chapters.

Renewable Generation

Unlike prior studies in the MIT *"Future of"* series, we do not assume a carbon-constrained world. Even in the absence of a broad federal initiative to reduce carbon dioxide emissions, however, federal and state subsidies and regulations are tilting the playing field in favor of low-carbon generating technologies. Beginning in the late 1970s, the federal government has supported the deployment of renewable energy sources—particularly geothermal, biomass, wind, and solar—through accelerated depreciation and, since the mid-1980s, tax credits for either production or investment, though support has been inconsistent over time.[24] All states now provide tax credits or other incentives for investment in renewable energy,[25] and 29 states and the District of

Columbia have renewable portfolio standards, which generally require utilities to obtain specified percentages of energy from designated renewable sources.

Renewables other than hydropower accounted for 4.2% of U.S. generation in 2010.[26] There is enormous regional variation: in California, for instance, renewables other than large hydro facilities accounted for 13.7% of electricity supply.[27] A number of states have set very ambitious requirements for renewables expansion: in California renewables other than small hydro plants will be required to account for 33% of electricity supply by 2020.[28] The EIA projects that even if support for renewables is not increased, but current federal policies are simply continued beyond their sunset dates, renewables other than hydropower will account for 57% of the increase in generation between 2010 and 2030, and wind and solar will account for over half of the non-hydro increase.[29]

Two features of these technologies pose potential problems for the electric grid. First, unlike most other generating technologies, the output of wind and solar generators varies considerably over time and is imperfectly predictable. For this reason, they and some other technologies are labeled "variable energy resources," or VERs. At low levels of penetration, VERs pose no new issues, but, as Chapter 3 discusses and several European systems have experienced, as penetration increases, demand minus VER generation (that is, the net load that must be met by other generators) becomes noticeably more variable and difficult to predict than demand alone. The system and its operation must be modified, at some cost, to handle this variability if reliability is to be maintained.[30] In particular as Chapter 3 notes, few incentives exist today for investments that add generation flexibility to power systems with organized markets or for operating in a flexible manner, though power system flexibility will become more important as the penetration of VERs increases.

FINDING

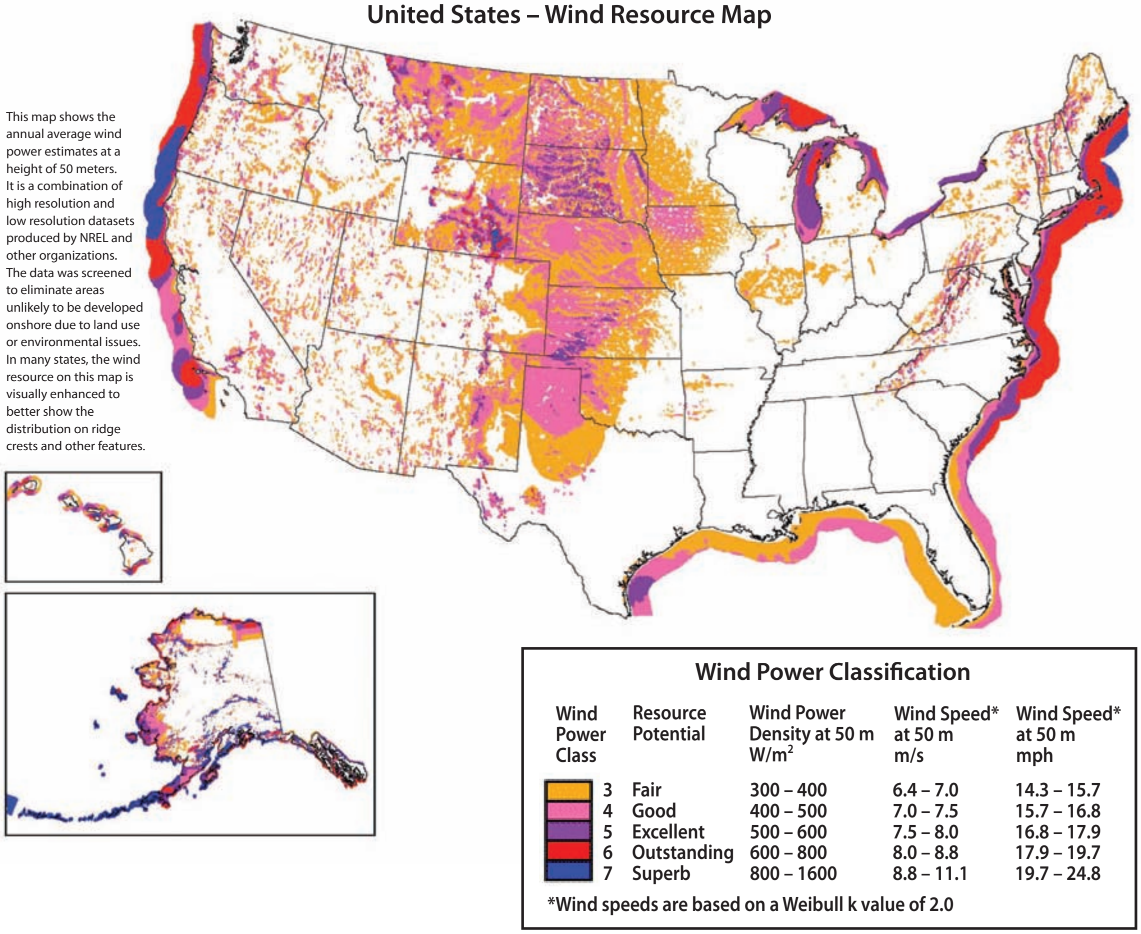
Devising and deploying mechanisms to provide incentives for investment in flexible generation and for operating flexibly within the system will become increasingly important as the penetrations of wind and solar generation increase.

Second, many of the most promising sites for wind and solar generators are located far from major load centers. As Figure 1.8 indicates, the most attractive wind resources are in the "wind belt" that stretches north from Texas through the Dakotas to the Canadian border. The U.S. also has significant offshore wind potentials on both the East and West Coasts. While these offshore resources are closer to major load centers, the costs of offshore wind installations are generally considerably greater than onshore facilities in good locations. Similarly, the prime locations for solar power are in the nearly cloud-free and sparsely populated desert Southwest, as shown in Figure 1.9.[iv]

Exploiting these variable energy resources will require building more transmission than if fossil-fueled or nuclear generating plants built relatively close to load centers were driving system expansion. The use of very long transmission lines can cause technical problems and compromise system stability. In addition, as Chapter 4 explains, existing transmission planning tools are inadequate for wide-area planning, and current cost-allocation methods need improvement.

[iv] Figure 1.9 relates to concentrated solar power generation, in which direct sunlight heats a working fluid (oil, historically), which is then used to generate steam to power a turbine. Photovoltaic systems are more tolerant of clouds (diffuse light) and hence perform well across a broader swath of the U.S. south.

Figure 1.8 Location of U.S. Wind Resources



Source: This information was prepared by the National Renewable Energy Laboratory for the U.S. Department of Energy. This image has been reprinted from the National Renewable Energy Laboratory's GIS website http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf, accessed November 16, 2011.

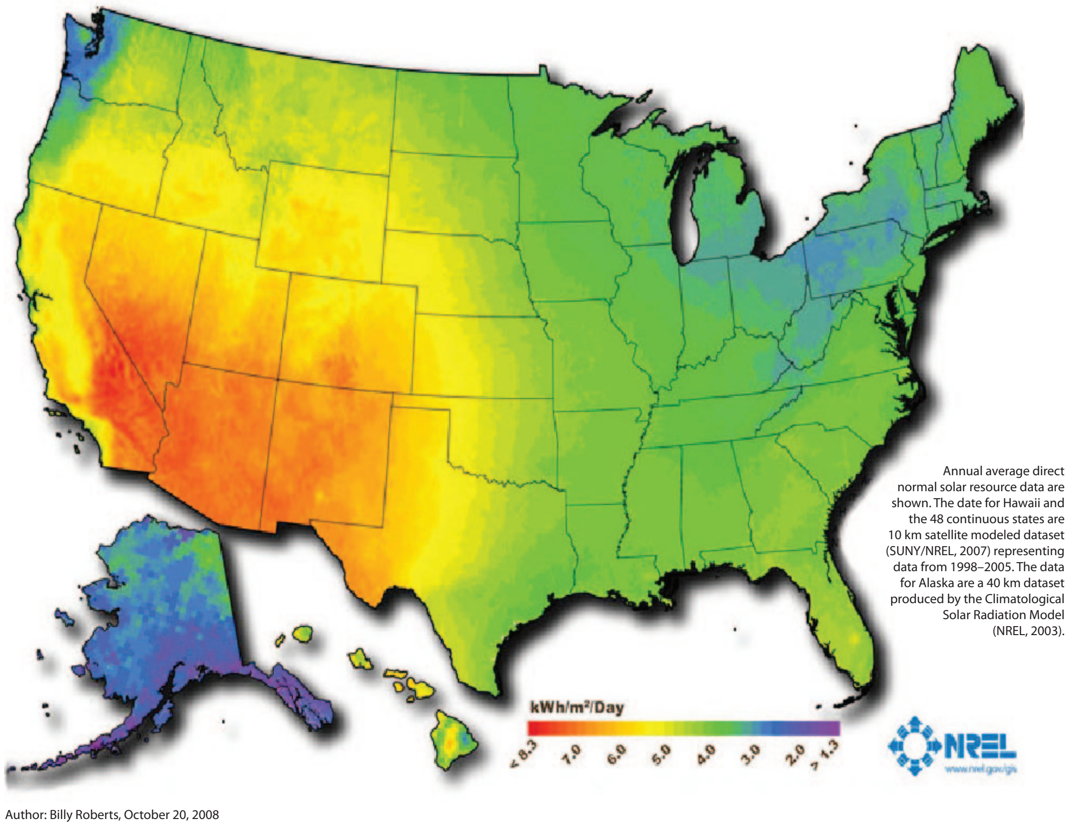
Cost allocation and siting have been particularly contentious for transmission facilities that cross state borders or the 30% of U.S. land managed by federal agencies. The Federal Power Act of 1935 made siting of all transmission lines a matter for the states rather than FERC, and lines that cross land managed by federal agencies need the approval of those agencies.[v] Consequently, the construction of interstate transmission facilities requires the consent of multiple state regulators and, sometimes, one or more federal agencies.

In some regions of the country, this process is facilitated by the historic cooperation of states within an ISO's territory. But as a general matter, the special difficulties of siting boundary-crossing transmission facilities will pose an obstacle to the efficient integration of renewable generation.[31]

The special difficulties of siting boundary-crossing transmission facilities will pose an obstacle to the efficient integration of renewable generation.

[v] In contrast to the Federal Power Act of 1935, the Natural Gas Act of 1938 as amended in 1947, gave the predecessor of FERC the right of eminent domain to site interstate natural gas pipelines. Interstate pipelines were already important in the natural gas industry in the 1930s, while interstate transmission of electricity was much less important than it is now or likely will be in the future.

Figure 1.9 Location of U.S. Concentrated Solar Power Resources



Source: This information was prepared by the National Renewable Energy Laboratory for the U.S. Department of Energy. This image has been reprinted from the National Renewable Energy Laboratory's GIS website http://www.nrel.gov/gis/images/map_csp_national_lo-res.jpg, accessed November 16, 2011.

FINDING

Efficiently increasing the penetration of grid-scale renewable generation while maintaining reliability will require modifications to power system design and operation. In addition, processes for planning transmission system expansion, allocating facility costs, and, particularly, siting interstate transmission facilities will need to be reformed.

Electric Vehicles and Greater Demand Variability

Although growth in electricity demand is not likely to emerge as an important source of disruption in the next few decades,[vi] electricity demand has changed and is likely to continue to change in ways that pose challenges to the system. The first of these has been a substantial increase in power demand during select hours of the year. Historically, several factors have contributed to this trend, which has resulted in an increasing ratio of system peak loads to average loads and falling capacity utilization.

[vi] Between 1949 and 1973, electricity use in the U.S. grew at an average annual rate of 8.3%, and the system was able to meet that demand with only sporadic difficulty. Even with rising prices after 1973, electricity use grew at an average annual rate of 2.5% in the 1973 to 2006 period. In contrast, the EIA's reference case projection is for growth to average only about 0.9% per year between 2010 and 2030.[32]

Figure 1.10 illustrates this change for New York and New England.

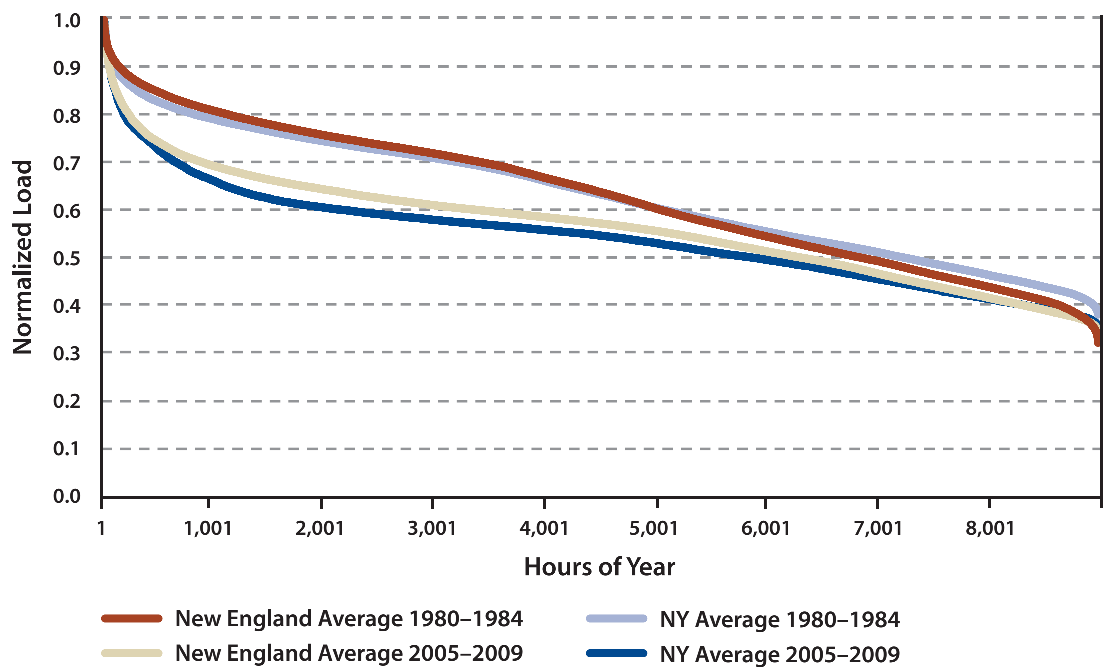
This figure shows load duration curves expressed as percentages of peak hour demand to facilitate comparisons. It shows, for instance, that in the 1980–1984 period in both New York and New England, demand exceeded 80% of its peak for only about 1,000 hours—about 11.4% of the time. Because power systems need to be sized to meet peak loads with a reserve margin for reliability, more than 20% of generation capacity (and, roughly, transmission and distribution capacity) was in use less than 12% of the time. The costs of that idle capacity must be covered by ratepayers, and the more that must be spent to build and maintain rarely used assets, the higher electricity rates must be.

Figure 1.10 also shows that, in the following quarter century, the problem grew appreciably worse. By 2005–2009, in both New York and New England, demand exceeded 70% of its peak for only about 1,000 hours so that more than 30% of capacity was in use less than 12% of the time. Not only does this trend raise average costs because of the need to pay for capital that is idle most of the time, it exacerbates the need to build new generation plants and transmission lines and thus the problem of siting them, since all new facilities must go in somebody's backyard.

By 2005–2009, in both New York and New England, demand exceeded 70% of its peak for only about 1,000 hours so that more than 30% of capacity was in use less than 12% of the time.

Among the factors that have contributed to the increasing severity of this problem are the spread of air-conditioning and the declining market share of industrial use of electricity. Between 1981 and 2001, the fraction of U.S. homes with air-conditioning rose from 57.3% to 75.5%.[33] This served to raise power demand most substantially in the hottest hours of the hottest summer days, which generally correspond to system peaks. We suspect this factor to have been particularly important in

Figure 1.10 Normalized Load Duration Curves for New England and New York



New York and New England in the period shown in Figure 1.10.

A second factor that may have been more important in other regions is the relative decline in industrial use of electricity. On average during 1950 to 1959, industrial customers accounted for half of retail sales of electricity.[34] Industrial plants often run around the clock all year, so the more important industrial load is, the flatter the load duration curve tends to be. The relative importance of industrial customers has declined steadily since the 1950s, however, and on average in the 2000 to 2009 period, they accounted for only 28% of retail sales. This has made load duration curves steeper.

Looking ahead, these trends are likely to continue, and their adverse effects on capacity utilization may be exacerbated by the spread of electric vehicles (EVs), which include plug-in hybrids and battery electric vehicles. About 94% of the energy used in the U.S. transportation system comes from petroleum, and more than half of crude oil and petroleum products are imported.[35] Increasing the penetration of EVs is often viewed as an attractive means of reducing dependence on imported oil. As Chapter 5 discusses, although their penetration generally is projected to be slow at the national level under current policies,[36] these vehicles cannot be ignored, even in the near term. EVs are expected to achieve high levels of penetration quickly in some high-income areas with environmentally conscious consumers. Whenever and wherever they are deployed in large numbers, their impact on the grid will depend on when they are charged. If they are charged when commuters return home, as seems most likely under current policies, they could add significantly to system peak loads, worsening the problem depicted in Figure 1.10. On the other hand, measures that encouraged overnight charging could increase demand when it would otherwise be low, thus tending to flatten load duration curves.

FINDING

Ongoing changes in the character of electricity demand and the future penetration of electric vehicles will, in the absence of other changes, tend to accelerate the decline in capacity utilization in the electric power system. This, in turn will increase electricity costs.

Distributed Generation

Existing policies at state and federal levels favor distributed generation from low-carbon sources, and these policies seem likely to continue. At the federal level, personal and corporate tax incentives encourage distributed generators, which are small-scale systems, generally connected to distribution networks. Most states have programs that subsidize distributed generation.[37] The California feed-in tariff program for small-scale renewable generation, particularly rooftop solar units, is perhaps the most visible of these.[38] In addition, 46 states and the District of Columbia have what are called "net metering" programs, which compensate end users for generating their own energy at the retail electricity rate rather than the wholesale cost of energy.[39] The difference between these rates is mainly the fixed cost of distribution (and, sometimes, transmission), which is typically recovered by per-kWh charges. When an end user increases generation, the system saves only the wholesale cost of energy. Under net metering, however, the end user saves both this wholesale cost and the per-kWh charge used to recover fixed network costs. Thus net metering provides an additional subsidy to distributed generation of all sorts that may encourage uneconomic penetration.

At low levels of penetration, distributed generation simply reduces the load at individual substations. At high levels of penetration, however, distributed generation can exceed load at the substation level, causing unusual distribution flow patterns with power flowing from the substation into the transmission grid. The systems involved are currently not designed to handle such reverse flows, however. In fact, this condition can produce high-voltage swings, which can be detrimental to customer equipment. High levels of penetration can also add to the stress on electrical equipment, such as circuit breakers, and complicate the ability to operate the distribution system, particularly during emergencies and planned outages. Additional monitoring and new standards for operation, protection, and control will be necessary to enable significant penetration of distributed generation. Enabling such penetration in a cost-effective manner would require incremental investment by the distribution utility, while distributed generation would reduce its sales. Current regulatory frameworks do not provide adequate incentives for such investments.

FINDING

High penetration of distributed generation complicates the design and operation of distribution systems. Net metering provides a subsidy to distributed generation, and utilities have inadequate incentives to make investments necessary to accommodate it.

Aging Workforce

Even if it faced none of the challenges discussed above, the electric power industry would need to rejuvenate its workforce in order to maintain current levels of performance. Prompted by the results of a National Science Foundation workshop on this topic in November 2007, the Power & Energy Society of the Institute of Electrical and Electronics Engineers (IEEE) founded the U.S. Power and Energy Engineering Workforce Collaborative (PWC) to lead efforts to strengthen the U.S. power and energy workforce.[40] In a widely cited April 2009 report, the PWC noted that approximately 45% of U.S. electric utility engineers would be eligible for retirement or could leave engineering for other reasons in the subsequent five years.[41] A 2008 survey conducted by the Center for Energy Workforce Development, an industry consortium, indicated that workforce attrition could amount to 40%–50% by 2013 across a wide range of power industry technical job categories, including lineworkers, pipefitters and pipelayers, engineers, plant operators, and technicians.[42] Beyond retirements, meeting the challenges and realizing the opportunities discussed in this study will also require many industry professionals to learn new skills and knowledge.[43] Unfortunately, university power engineering programs have languished over the past several decades due to the increasing popularity of other electrical engineering subdisciplines and a lack of research funding to support graduate students.[44] Furthermore, a recent survey

University power engineering programs have languished over the past several decades due to the increasing popularity of other electrical engineering subdisciplines and a lack of research funding to support graduate students.

indicated that approximately 40% of power engineering faculty members at U.S. universities will become eligible for retirement within the next five years, and 27% are expected to retire.[45] While it is difficult to predict exactly how many new engineers will be needed between now and 2030, there appears to be a significant gap between anticipated industry demands and both the pipeline of students entering power engineering and the faculty in place to train them.

Fortunately, industry workforce challenges have received increasing attention in the past several years. Among other efforts, the PWC has published a detailed action plan with recommendations for a wide range of industry stakeholders.[46] The DOE also recently awarded $100 million to 52 workforce training and development efforts.[47] These projects are expected to help train as many as 30,000 workers and develop a variety of power system education programs. It is too early to tell whether these efforts will be sufficient to ensure the availability of a qualified technical workforce, however, and the issue will likely continue to receive attention in the years ahead.

FINDING

Because of its aging workforce and the nature of emerging challenges, the electric utility industry faces a near-term shortage of skilled workers, particularly power engineers. While this problem has been widely recognized, it remains to be seen whether efforts to deal with it will prove adequate.

Technologies for Reliability and Efficiency

The electric power system is built to handle periodic equipment failures, primarily by rapidly disconnecting lines or generators where problems occur. To guard against the negative consequences of contingencies in the bulk power system, such as the loss of a generator or transmission line, system operators maintain a prescribed level of generation reserves and updated procedures for reacting to unexpected events. These measures work well most of the time, and customers are often unaware when problems occur on the bulk power system. Customers more often observe failures of the distribution system. If a tree limb takes down a distribution line, for instance, many utilities do not know where to send a repair truck until multiple customers have reported the outage.

Innovative technologies can improve operator knowledge about the state of the transmission system and thus make possible more efficient and reliable operation.

As discussed in Chapter 2, innovative technologies can improve operator knowledge about the state of the transmission system and thus make possible more efficient and reliable operation. On the transmission system, phasor measurement units (PMUs) are powerful devices that provide rich streams of frequent, time-stamped data on transmission system conditions that system operators can use to anticipate contingencies, reduce the risk of wide-area blackouts, enhance system efficiency, and improve system models. With funding from the American Recovery and Reinvestment Act of 2009, PMUs are being widely deployed, but work is needed to network these devices into systems, convert data from these systems to actionable information, and employ this information in the control of the grid.

In addition to PMUs, flexible alternating current transmission system (FACTS) devices based on advances in power electronics can provide greater control of voltages and power flows throughout the bulk power system.

FACTS and other new technologies can allow more power to be transmitted on existing lines without increasing the risk of failure, but historically the incremental benefits generally have not justified the associated costs. Higher penetration of VERs is likely to increase the value of deploying these technologies in the transmission system.

Compared to the transmission network, the distribution system uses more basic, inexpensive monitoring and control equipment. This is cost-effective, as there are far more miles of distribution lines than transmission lines, and each distribution line serves fewer customers than a transmission line. There are many technologies to enhance the distribution system, as Chapter 6 explains, including distribution management system software, more accurate control of voltages, automatic reconfiguration of distribution circuits, and advanced metering infrastructure (AMI). AMI, for instance, will enable system operators to detect an outage and identify its cause within minutes, even if no customers call.

Because it is often more cost-effective to invest in monitoring and control systems at the transmission level than the distribution level, many available technologies have not yet been widely implemented at the distribution level. Moreover, in recent years U.S. utilities and regulators have tended to avoid investments in unfamiliar technologies perceived to have uncertain payoffs. Given the many new challenges that will confront distribution systems in the next 20 years, some modernization and enhancement will surely be appropriate, but each system is different, and cost is always an important consideration in the choice of technology.

In addition, as discussed in Chapter 6, a variety of new and emerging technologies, including advanced metering systems, can receive price information based on the real-time cost of providing electricity and can transmit usage information every few minutes. This makes it possible to provide real-time incentives to reduce system peaks caused by central air-conditioning, vehicle charging, and other loads, resulting in more efficient use of grid assets and thus lower rates. As Chapter 7 notes, however, the effective use of these technologies to make electricity demand more sensitive to system conditions will require changes in regulatory policy to encourage the deployment of relatively novel pricing regimes, to which customer response, especially at the retail level, is poorly understood.

FINDING

New technologies have the potential to improve the reliability and efficiency of bulk power systems by enhancing operators' ability to observe and control these systems. Technologies similarly can enhance distributions systems and make demand more responsive to real-time costs, but effective use of these technologies will require changes in regulatory policy.

BOX 1.2 THE "SMART GRID"

The term "smart grid" has been used to refer to a wide variety of electric grid modernization efforts and ideas over the past several years. While uses of the term vary throughout industry, government, and the public, it is perhaps best described as the expanded use of new communications, sensing, and control systems throughout all levels of the electric grid. Many industry websites have been created to try to make sense of the flood of "smart grid" ideas, concepts, and products originating from industry, organizations, and individuals. These websites include SmartGrid.gov (www.smartgrid.gov), the Smart Grid Information Clearinghouse (www. sgiclearinghouse.org/), and IEEE's Smart Grid site (http://smartgrid.ieee.org/).

In the U.S., Title XIII of the Energy Independence and Security Act of 2007 established the development of the smart grid as national policy and identified it as a broad collection of ambitious goals, some of which seem only loosely connected to the grid's intelligence, as follows:

SEC. 1301. STATEMENT OF POLICY ON MODERNIZATION OF ELECTRICITY GRID.

It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cybersecurity.
3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy efficiency resources.
5. Deployment of `smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6. Integration of `smart' appliances and consumer devices.
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage airconditioning.
8. Provision to consumers of timely information and control options.
9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

The scope of this study is broader than many definitions of the smart grid. However, we do consider the technologies that are core to most smart grid discussions. For example, phasor measurement units, devices that have the potential to equip bulk system operators with greater real-time knowledge of the state of the bulk transmission system, are discussed in Chapter 2; applications that are enabled by the deployment of sensors and communications throughout distribution networks are described in Chapter 6; and advanced metering infrastructure investments are discussed in Chapter 7. Chapter 9 analyzes many of the challenges related to expanded data communications use, including cybersecurity and information privacy challenges.

Because the term "smart grid" means different things to different people and because its meanings are evolving, we have avoided reliance on the term in this report. We have focused instead on the broad goal of making the grid of the future more resilient, secure, efficient, and reliable amid a variety of emerging challenges and, perhaps, to enable the provision of desirable new services. Seizing opportunities related to recent or anticipated technical innovations can further these goals.

Cybersecurity and Privacy

The interconnection of small, local power systems enhanced reliability overall but made possible wide-area blackouts. Similarly, the increasing use of new sensing and automated response technologies will enhance reliability and efficiency overall but create new problems.

As explained in Chapter 9, increasing amounts of data will be exchanged among meters, other sensors, and various computers and control facilities through a complex communications system that must follow standards that allow various components to interoperate now and in the future, when later generations of equipment are installed. Since no communications system can be completely free from errors, the future grid must be designed to mitigate the consequences of data errors. More chilling is the possibility of deliberate sabotage via computers and data communications, the sort of cyber-attacks that other industries have experienced. The existence of more communications nodes and channels facilitates the placement of malicious data into the system; in addition, greater reliance on automated responses to system conditions that may be misreported can make it more difficult to prevent serious damage.

With the collection, transmission, processing, and storage of increasing amounts of information also comes heightened concern for protecting the privacy of that information.

With the collection, transmission, processing, and storage of increasing amounts of information also comes heightened concern for protecting the privacy of that information. As advanced metering is implemented, information on personal habits will be available to electric companies at a level never before envisioned by today's utilities, nor by today's policy makers. Information about the operation of the electric grid itself will soon be available at a level of detail that will be of value to those with both commercial and malicious interests.

Deciding who has access rights to these personal data and ensuring consumers' privacy will be an important consideration in the design and operation of grid communications networks. Many governments have passed laws protecting the privacy of personal information, although not yet specifically electricity usage information. Utilities and related organizations will have to develop systems and procedures to protect the privacy of grid information to satisfy the concerns of customers and their governments.

FINDING

Greater reliance on data communications in the grid increases the importance of standardization for interoperability and of cybersecurity and raises serious issues of privacy.

1.3 MAJOR RECOMMENDATIONS

This section highlights what we consider the most important elements of the more than 20 specific recommendations developed in later chapters and discusses some of our related findings and conclusions. We present recommended policy changes affecting transmission, pricing and regulation of distribution, and cybersecurity. Major recommendations for research and analysis and for data development and sharing are collected in the final subsections below.

Two broad points deserve mention here. First, the adoption of coherent and stable national policies on greenhouse gas emissions, electric vehicles, and renewable and distributed generation would enhance investment incentives and thereby accelerate the appropriate evolution of the grid. Second, support for organized wholesale electricity markets along with open, nondiscriminatory access to the transmission grid has been repeatedly affirmed as national policy, but development and expansion of the reach of open access and nondiscrimination is still a work in progress.

Support for organized wholesale electricity markets along with open, nondiscriminatory access to the transmission grid has been repeatedly affirmed as national policy.

These policies are of central importance for the transmission grid, and organized electricity markets with many common market design elements will continue to define the framework within which they can be effectively implemented.

Bulk Power and Transmission Systems

As generation from wind and solar power grows in importance, power systems will have to become more flexible to be better able to respond to substantial changes in the output of these variable resources. System operators here and, especially, in Europe are aware of the problems involved, and solutions are being developed. It seems clear that real or virtual consolidation of small balancing areas would be helpful, as would requiring new VER generators to meet performance specifications appropriate for operation in a high-VER future. And, as we noted earlier, mechanisms to ensure that power systems are adequately flexible will become more important in the future.

As the electric power system has become increasingly interconnected, the importance of transmission lines that cross state borders or federal lands has also increased. And, as discussed earlier, public policies favoring renewable generation are likely to accelerate this trend because many of the best wind and solar resources are far from major load centers.

Transmission system expansion in many regions is routinely planned on a multistate basis, and attempts at interconnection-wide planning are under way. FERC Order No. 1000, issued in July 2011, should significantly increase wide-area planning of transmission systems and rationalize the allocation of the costs of transmission facilities that cross regional boundaries. We nonetheless believe the public interest would be served if the affected parties went beyond the order's planning requirements and established permanent and collaborative processes for transmission planning at the interconnection level that combine top-down and bottom-up approaches. Similarly, while Order 1000 only requires the development of bilateral cost-allocation procedures for interregional projects, we believe all affected parties should develop a single procedure for each interconnection. In that procedure, as Chapter 4 explains, costs should be allocated as closely as practical in proportion to anticipated benefits and other efficiency-enhancing principles should be followed.

Under current law, states retain the primary role in siting transmission facilities, and their interests sometimes conflict.

Under current law, states retain the primary role in siting transmission facilities, and their interests sometimes conflict. Any involved state can block a multistate project. Moreover, federal agencies with missions that include purposes unrelated to energy manage 30% of U.S. lands; they can and do exercise the power to block or delay the construction of transmission lines across these lands in cases of perceived conflict with other land management missions.

The federal government has addressed this type of structural problem before. In 1938, recognizing the growing importance of interstate natural gas pipelines, Congress gave FERC authority to site these facilities, now including the power of eminent domain. In recognition of the increasing importance of interstate electricity transmission, the Energy Policy Act of 2005 contained a section that was intended to give FERC useful backup siting authority in the event states disapproved construction of multistate electricity transmission facilities. As Chapter 4 discusses, however, subsequent court decisions have effectively annulled that section. While the Obama administration has recently taken steps to streamline federal agency participation in some siting decisions by creating the Renewable Energy Rapid Response Task Force, the current system for siting transmission facilities remains a significant barrier to efficient expansion of the grid.

Some have argued that in the interest of efficiency, FERC should have sole siting authority over major projects, as it does over interstate natural gas pipelines. Others contend that giving FERC effective backstop authority would create a process more sensitive to states' legitimate concerns. While both approaches clearly have strengths and weaknesses, adopting either would be a significant and important improvement over the status quo.

RECOMMENDATION

New legislation should grant FERC enhanced siting authority for major transmission facilities that cross state boundaries or federal lands (Chapter 4).

Pricing and Distribution Regulation

As noted earlier, in recent decades the ratio of peak electricity demand to average demand has increased, and this trend is likely to continue. Since an essential requirement of a power system is the ability to meet peak demand, these developments have reduced capacity utilization and thereby increased average cost and, ultimately, retail rates. The penetration of electric vehicles may exacerbate this trend unless their owners can be induced to charge them in off-peak periods. Even greater savings may be realized by making other loads, including commercial and industrial HVAC systems and residential appliances, similarly responsive to system conditions. Existing studies suggest that regulators and utilities can achieve this using a combination of dynamic pricing—in which retail prices vary over short time intervals to reflect the often dramatic changes in the actual cost of providing electricity—combined with technology to automate response to price changes.

The behavior of residential consumers faced with dynamic pricing is not yet adequately understood.

Many large commercial and industrial customers now operate under dynamic pricing. We believe such pricing regimes will be widespread options, if not the default, for residential consumers also by the end of our study period in 2030, with third parties generally enabled to compete to provide equipment to automate response to price changes. However, response automation technologies are not yet mature, in part because the behavior of residential consumers faced with dynamic pricing is not yet adequately understood, and residential dynamic pricing requires substantial investment in AMI to measure usage over short time intervals. Substantial AMI investments have recently been funded through the Recovery Act of 2009, and some state regulators have mandated universal AMI deployment. But movement toward the dynamic pricing regimes that AMI enables has been slow. Given the enormous potential value of dynamic pricing of electricity, regulators and utilities should exploit the important learning opportunity the Recovery Act-supported and regulator-mandated investments in AMI have provided to develop efficient paths to universal dynamic pricing—and then to follow those paths.

RECOMMENDATION

With the cooperation of their regulators, utilities that have committed to AMI systems should begin a transition to dynamic pricing for all customers and publicly share data from their experiences (Chapter 7).

Utilities that have not committed to AMI systems and for which the operational benefits of these systems are less than their cost should take advantage of the option to learn from early adopters before making a decision to invest. For jurisdictions with wholesale electricity markets, effective competition in the retail sales of electricity may stimulate innovation in ways to make dynamic pricing both acceptable to consumers (and regulators) and effective in modifying demand.

Electricity pricing also needs to be changed to deal with the growth of distributed generation and energy efficiency initiatives. Utilities currently recover the largely fixed costs of transmission and distribution networks through volumetric charges per kilowatt hour of use, a practice that distorts the relative prices of central station generation and distributed generation. Under this regime, a customer who generates electricity on-site rather than purchasing it from the local distribution utility saves both the energy charge and the distribution charge for that electricity, but the utility saves only the corresponding generation cost because the cost of distribution is almost entirely unchanged. (Indeed, if a high concentration of distributed generation required modification of the distribution system, that fixed cost may be increased.) This outcome is the same regardless of the energy source—clean solar or dirty diesel—used by the distributed generator. The remedy is straightforward, at least in principle: recover fixed network costs mainly through nonvolumetric charges.

RECOMMENDATION

State regulators and those who supervise government-owned and cooperative utilities should recover fixed network costs primarily through customer charges that may differ among customers but should not vary with kilowatt-hour consumption (Chapter 8).

These fixed charges could depend on indicators of customers' need for network capacity. For example, customer groups that are expected to contribute more to local peak demand based on their pattern of prior consumption could pay a higher fixed charge than customer groups that are expected to contribute less. Systems that continue to rely significantly on volumetric charges for cost recovery should improve utility incentives by decoupling utility revenues from short-run changes in sales.

Coping efficiently with the integration of distributed generation, electric vehicles, and demand response in coming years will require significant investments in new and emerging technologies that will be riskier than most recent investments in distribution systems; they will aim to provide new capabilities, not just expand capacity in traditional ways. While the technical problems associated with these new challenges are real, they do not appear to be serious. However, the tendency of traditional regulatory systems to encourage excessively conservative behavior is likely to become more and more expensive over time if increasingly attractive opportunities to enhance efficiency and reduce cost through innovation are not exploited. As Chapter 8 discusses, this is an important problem—but one without an obvious solution, since both regulators and utilities seem to be punished for bad outcomes but not rewarded for good ones. Nonetheless, regulatory innovations are necessary to provide adequate incentives for investments in unfamiliar technologies while also ensuring that the returns on these investments are shared appropriately with ratepayers.

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Communications, Cybersecurity, and Privacy

As data communications becomes more important in the grid, so will problems of cybersecurity and issues of privacy. As the grid evolves, it will be critical to maintain interoperability of different types and generations of components over a variety of networks with, most likely, a variety of owners. The National Institute of Standards and Technology (NIST) is overseeing the complicated process of developing the relevant interoperability standards. This process is critical, and it should be encouraged and supported. In addition, there are ongoing debates about the use of spectrum and the roles of public and private networks. Resolution of the former debate rests with the FCC, while we expect that opportunities for both public and private networks will exist unless the regulatory environment treats them unequally.

As communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyberattacks.

As communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyberattacks.

Response and recovery, in addition to preparedness, will thus be important components of cybersecurity. NERC is responsible for standards development and compliance for the bulk power system, but no entity has comparable nationwide responsibility for distribution systems. State PUCs (which are generally responsible only for investor-owned distribution systems), municipal electric systems, cooperatives, and other public systems generally lack the expertise necessary to deal with cybersecurity issues. While the consequences of a successful attack on the bulk power system are potentially much greater than an attack at the distribution level, the boundary between transmission and distribution has become increasingly blurred, and distribution-level cybersecurity risks deserve serious attention. NIST is facilitating the development of cybersecurity standards broadly, but it does not have an operational role. Thus no organization currently has responsibility for overseeing grid cybersecurity across all aspects of grid operations.

RECOMMENDATION

The federal government should designate a single agency to have responsibility for working with industry and to have the appropriate regulatory authority to enhance cybersecurity preparedness, response, and recovery across the electric power sector, including both bulk power and distribution systems (Chapter 9).

This may require new legislation, and legislative proposals designating either a combination of FERC and DOE or the Department of Homeland Security (DHS) have been advanced. The various agencies each have both strengths and weaknesses for such a designation; the capabilities of any agency can be enhanced to address its relevant weaknesses, but ongoing jurisdictional confusion raises security concerns, underscoring the need for action. Once a lead agency has been designated, it should take all necessary steps to ensure that it has appropriate expertise by working with other relevant federal agencies, NERC, state PUCs, public power authorities, and such expert organizations as IEEE and EPRI.

Finally, the issues involved in the use and protection of customer electric usage data are complex, particularly because of the many different and evolving views of consumers, utilities, and regulators. These issues continue to be actively debated in several states. Coordination across states will be necessary to mitigate concerns of companies that operate in multiple jurisdictions and of their customers, as data on both companies and their customers cross state boundaries.

Research and Analysis

As noted earlier, the electric utility industry traditionally has relied primarily on its suppliers for the innovation that has driven its productivity growth. Supplier R&D naturally has focused on equipment that can be sold to utilities. Additional efforts in several non-equipment related research areas relevant to tomorrow's grid are likely to have substantial payoffs, and these are not likely to attract traditional equipment vendors. They include the development of computational tools and well-designed social science–based studies of customer response to dynamic pricing regimes, perhaps supported by response automation, that have been made possible by recent AMI investments.

Currently, electric utilities generally lack both appropriate financial incentives and the expertise necessary to perform either type of research and development, but the industry should nonetheless be able to support the modest but sustained efforts required. For this to happen, regulators will need to recognize that technical progress benefits consumers broadly and permit modest increases in utility R&D budgets. It will also likely be necessary for the industry to reverse the downward trend in cooperative R&D spending and make appropriate use of cooperative funding through EPRI, one or more independent system operators, and project-specific coalitions.

New algorithms, software, and communication systems are required to integrate PMUs and FACTS devices effectively into system operations. The Recovery Act has funded expansion of PMU penetration in the grid. Like the Recovery Act–financed investment in AMIs, this investment provides an important learning opportunity. If shared, data generated by existing PMUs can be used to develop algorithms and establish baselines for future operational tools that can monitor and control networks with greater PMU and FACTS penetration.

Existing planning methods cannot do multiperiod optimization under uncertainty for networks with anything approaching the complexity of the Eastern or even the Western Interconnection.

The wider the area over which transmission planning is done, the more complex the problem becomes. Existing planning methods cannot do multiperiod optimization under uncertainty for networks with anything approaching the complexity of the Eastern or even the Western Interconnection. As noted earlier, the grid is becoming more closely coupled at the interconnection level partially because of the challenge of efficiently integrating remote renewable generators. As discussed earlier, some interconnection-level planning efforts are under way, and FERC's Order No. 1000 calls for an expansion of the geographic scope of planning processes. The development of new planning methods, discussed in Chapter 4, thus has a high potential payoff.

As noted earlier, perfect protection from cyberattacks is not possible. There will be a successful attack at some point. It is thus important for the involved government agencies (i.e., NIST, DOE, FERC, and DHS), working with the private sector in a coordinated fashion, to support the research necessary to develop best practices for response to and recovery from cyberattacks on transmission and distribution systems, so that such practices can be widely deployed.

Finally, as discussed earlier, the industry should use the first round of AMI deployments to learn how best to employ the capabilities of these systems and response automation technologies to make electricity demand more responsive to system conditions. Among other things, further research on consumer reactions to dynamic pricing is needed, and effective consumer engagement and education strategies must be designed and tested in the field.

RECOMMENDATION

The electric power industry should fund additional research and demonstration projects to develop: computational tools that will exploit the potential of new hardware to improve monitoring and control of the bulk power system (Chapter 2); methods for wide-area transmission planning (Chapter 4); processes for response to and recovery from cyberattacks (Chapter 9); and understanding of consumer response to alternative pricing/response automation systems (Chapter 7).

Data Development and Sharing

In the course of this project, we have been struck repeatedly by shortcomings in the data available on the U.S. electric grid to researchers and to decision makers in both government and industry. Even though this problem has been observed and commented upon repeatedly, it persists.[48] Sometimes available data are not shared as widely as would be beneficial. Sometimes potentially valuable data are simply not collected or are compiled in ways that limit their usefulness. Good data are critical inputs to good decisions regarding the grid, especially in the unfamiliar situations in which public and private actors will increasingly find themselves.

We have been struck repeatedly by shortcomings in the data available on the U.S. electric grid.

One promising recent initiative has been undertaken to enhance high-value data sharing. In February 2010, NERC created two nondisclosure agreements to facilitate sharing PMU data. Unfortunately, a year and a half later, many utilities with significant PMU deployment activity had not yet signed these agreements. If this initiative fails to achieve the hoped-for results, the benefits of PMUs may not be realized. The responsible federal agencies should take steps to ensure that the critical data at issue are shared appropriately.

We have identified three additional areas in which ensuring the appropriate availability of useful data would be particularly valuable. While network data on the Western Interconnection are available at a level of detail adequate to support analysis, such data are not available for the more complex Eastern Interconnection. This inhibits both wide-area planning and the improvement of wide-area planning methods. Obviously, the general availability of detailed data on the U.S. bulk power system would raise serious security concerns, but federal agencies have a good deal of experience making confidential data available for use in research while ensuring that confidentiality is not violated and data are not copied.

In this regard, we note that there is a lack of information currently available on projects that had been funded through DOE's Smart Grid Demonstration Program and Smart Grid Investment Grants initiatives. Achieving the full potential of these distribution system technology demonstration projects will require that data on both successes and failures are shared widely. Several websites, including www.smartgrid.gov and www.sgiclearinghouse.org, have been established to disseminate information about these projects. As results become available, it is imperative that resources such as these are effectively used to share data and lessons learned.

Electric utility customers care about reliability, customer service, and other dimensions of performance as well as cost, and those concerns are arguably increasing as the share of energy used to power computers and other complex electronic equipment rises. While regulators have at times considered performance in an ad hoc, case-specific fashion when setting allowable rates of return, a more systematic approach would almost certainly produce better results. Some U.S. regulators and many abroad have accordingly begun to establish explicit, formal incentives based on performance metrics. But, as noted earlier, many jurisdictions do not even require utilities to report data on reliability in a useful form, let alone data on efficiency or other aspects of performance. The lack of comprehensive, comparable data hinders regulators' attempts to evaluate utilities over time or make useful comparisons across utilities, especially those in different jurisdictions. To the ultimate benefit of all stakeholders, development and publication of standardized cost and performance metrics would facilitate assessment of utility outcomes and make it easier for regulators to provide meaningful incentives for good performance.

RECOMMENDATION

FERC should require that detailed data on the U.S. bulk power system be compiled and made appropriately available (Chapter 4). DOE should work to ensure that comprehensive data from its Smart Grid projects are widely shared (Chapter 6). State regulators and others supervising distribution utilities should require utilities to compile and publish standardized metrics of utility cost, reliability, and other dimensions of performance (Chapter 8).

1.4 CONCLUDING REMARKS

Between now and 2030, the electric grid will confront significant new challenges and inevitably undergo major changes. Despite alarmist rhetoric, there is no crisis here. But we do not advise complacency. The environment in which the grid will operate will change substantially in the next two decades. If the grid is to evolve with minimal disruption despite the challenges ahead and if electricity rates and levels of reliability are to be acceptable, decision makers in government and industry need to continue to focus on meeting the system's challenges. A range of system-level issues need to be addressed, and new technologies need to be used as appropriate. Regulators should seek to develop policies that better align incentives of participants in electricity markets (including consumers) with policy goals. The industry needs to conduct research in key areas and both collect and share important data.

We are encouraged by recent levels of awareness, concern and, in some key areas, action. But the journey to the electric grid of 2030 has begun, and there will be plenty of surprises along the way. As this study indicates, much can and should be done now to smooth the potentially very bumpy road ahead.

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Chapter 2: Enhancing the Transmission Network and System Operations

In this chapter, we provide an overview of today's transmission network technologies and power system operations, then discuss new technologies that could help prevent blackouts, increase transmission capacity, and improve system operations. The issues in this chapter are primarily the concern of utility engineers, grid operators, and transmission planners; accordingly, this chapter does not deal with regulatory topics, which are addressed in Chapter 4, or contain policy recommendations. Even so, we believe an understanding of transmission technologies and the operation of the power system provides important context for policy makers.

Section 2.1 provides an introduction to the transmission network and system operations, starting with transmission lines and substations. It then explains how power systems are operated and briefly discusses transmission system reliability. This is followed in Section 2.2 by a description of technologies that could reduce the frequency of major blackouts, including phasor measurement units (PMUs), wide-area measurement systems (WAMS), and flexible alternating current transmission systems (FACTS). We find that phasor measurement units have the potential to greatly benefit the transmission network, but mechanisms for sharing data are immature, and many tools for data analysis have yet to be developed.

Section 2.3 introduces technologies that can facilitate the expansion of the transmission network and describes the fundamental physical characteristics that impose limits on transmission capacity and how these limits determine the technologies most appropriate for long-distance transmission. The section also discusses promising emerging technologies, such as superconductors and dynamic line rating systems, that can increase transmission network utilization and capacity.

Section 2.4 describes a range of new technologies that could enhance system operations. We find that the development of control algorithms that can utilize data from PMUs and exploit the capabilities of FACTS technologies are important areas for research.

The transmission network is the first link between large power generation facilities and electricity customers. It supplies energy at high voltages to substations, where the energy is distributed to loads at lower voltages via the distribution network. The transmission network today operates reliably and efficiently, but a variety of technologies offers the potential to improve system performance. Sophisticated new monitoring systems may reduce the likelihood of rare cascading system failures, which can have serious economic and social consequences. More efficient or lower-impact technologies may help solve problems associated with network expansion, including difficulty in siting new transmission lines to meet growing demand amid increasing pressure to limit environmental impact. And changes in system operation will help incorporate growing penetrations of variable energy resources, like wind and solar generation.

2.1 THE TRANSMISSION NETWORK AND SYSTEM OPERATIONS

In the U.S., the transmission network is divided into three distinct geographic regions called interconnections: the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas (ERCOT) (see Figure 1.2). Only weak electrical links exist between them. Altogether, the U.S. transmission network consists of approximately 170,000 miles of lines at 200 kilovolts (kV) and higher, linking electricity consumers to almost 5,000 large power plants.[i, 1] Table 2.1 contains a breakdown of transmission lines in the U.S. by miles and voltage level. The companies that own and operate these lines range from large investor-owned utilities, which control thousands of miles of lines spread over multiple states, to transmission owners with only a handful of short transmission links.

Table 2.1 Approximate U.S. Transmission Line Miles by Voltage

Line Type	Voltage (kV)	Miles
Alternating Current (ac)	200–299	84,000
	300–399	54,000
	400–599	26,000
	≥ 600	2,400
	Total ac	161,000
Direct Current (dc)	200–299	700
	300–399	0
	400–599	1,800
	≥ 600	0
	Total dc	2,500
	Total	**169,000**

Source: North American Electric Reliability Corporation (NERC) Electricity Supply & Demand Database, http://www.nerc.com/page.php?cid=4|38.

Transmission Lines

Transmission lines carry energy; the rate at which energy flows is measured as power.[ii] Power is proportional to the product of current and voltage; higher voltage and current correspond to higher power. Generators and other devices manipulate the distribution of power among lines by controlling voltages at the two ends of lines (for further explanation on the nature of power flows, see Box B.1 in Appendix B). Power on individual lines cannot be precisely controlled, though new devices discussed later in this chapter are improving the ability of system operators to do so.

Power on individual lines cannot be precisely controlled.

The interconnectedness of the grid compounds the difficulty in controlling power. Multiple transmission lines often intersect at one substation, making it impossible to change the flow on one line without affecting others. As a consequence, energy flowing from one location to another follows multiple paths and may cross jurisdictional boundaries. These so-called loop flows can create adverse or beneficial physical and economic effects in several jurisdictions.

The related problem of congestion results in adverse economic consequences by preventing the least-cost set of generators from supplying load. A transmission line is limited in its capacity—that is, how much power it can carry—by several mechanisms, discussed in Section 2.3. It is impossible to use the least-cost set of

[i] Almost 5,000 generating units with at least 50 megawatts of expected on-peak summer capacity were registered with the North American Electric Reliability Corporation in 2010.

[ii] Though it is energy, not power, that "flows" through transmission lines, it is common industry practice to speak of power flows rather than energy flows. With some exceptions, we use the common industry vernacular in this chapter.

generators to supply additional load when one or more transmission lines reach a limit and are unable to carry the required additional power. When lines are thus congested, other, less economically efficient generators are dispatched to supply the load avoiding the transmission network limits. Such costs can be significant in some cases; the cost of congestion in the PJM Interconnection was estimated to be about 6% of total electricity billings in 2008.[2]

Substations and Voltage Support

Transmission substations house much of the equipment necessary for the normal functioning of the transmission network and system operations. The primary function of transmission substations is to interconnect transmission lines. These lines may all be at the same voltage, or the substation may contain transformers to connect transmission networks of different voltages. These transformers also are necessary to connect the transmission system to the lower-voltage distribution system. Voltage is typically decreased in several steps at substations along the transmission and distribution systems using transformers before reaching customers. In addition, substations provide protection for lines and equipment with devices such as protective relays, circuit breakers, and surge arresters. Finally, substations contain measurement and communication equipment that bring data to control centers and voltage compensation devices that keep voltages within acceptable limits.

Maintaining voltage within a specified range along the entire length of an ac line may require special devices and control procedures. As a line is loaded—that is, as its current is increased—the voltage drop along the line from the generator to the load will increase. The process of bringing the voltage back within acceptable range is known as voltage support or volt-ampere reactive (VAR) support.[iii] Voltage support is necessary to maintain acceptable voltage levels and power transmission capacity as the length and loading of lines increases. Until recently, common practice was to provide voltage support by connecting compensating devices, such as capacitor banks, to the line and controlling their voltage contribution in response to changes in load. Newer technologies employ semiconductor switches and can provide more precise control and faster response to changes in load. These devices are known as static VAR compensators (SVCs) and are one member of a class of new devices comprising flexible ac transmission systems (FACTS), which are discussed later in this chapter.

SVCs are an established technology with many years of operational deployment. The first were installed in the early 1980s, and many more installations have followed in the U.S. and internationally.[3] The decision to use an SVC instead of a capacitor bank is an economic one; the value of the operational benefits of fast and flexible response is balanced against the increased cost and energy losses of the SVC.

FINDING

Technologies exist, which if found to be economically justifiable, could improve the performance of the transmission system.

[iii] VAR is the unit used to measure reactive power, which is present in an ac system when current and voltage are not in phase.

System Operation

Power systems require a level of centralized planning and operation to ensure system reliability. System operators at control centers carry out many of these centralized functions in support of operations, including short-term monitoring, analysis, and control. A single electrical interconnect contains many system operators. For example, in the Eastern Interconnection, system operators at the regional level include the New York Independent System Operator (ISO), ISO New England, Midwest ISO, PJM, Tennessee Valley Authority, Southwest Power Pool, and others. Transmission and generation owners that operate their own assets and coordinate with these regional entities also are called system operators.

Control centers perform three separate functions:

- **Monitoring:** System operators use various displays and alarms to develop awareness of the state of the system.

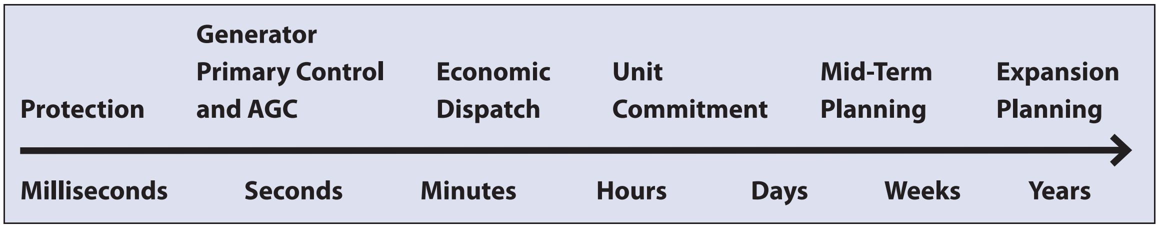
- **Analysis:** Raw data reported to control centers are analyzed using computer tools that can give insight to the current and future state of the grid. This suite of tools is collectively known as an energy management system.

- **Control:** Regional control centers calculate the expected hourly power output of generating units for the next day or days based on projected electricity demand and relay this information to generating units. The decision of which generators should be on or off for the next day is known as unit commitment. The specification of the amount of power each of those committed generators should produce is known as economic dispatch. In areas with traditional vertically integrated utilities, economic dispatch and unit commitment are calculated based on known start-up and fuel costs for generators; in restructured areas, a similar result is obtained through bidding in wholesale markets. Control centers then refine these day-ahead estimates as often as every 5–15 minutes, dispatching each generator to minimize total system costs given the load level, generator availability, and transmission constraints. Control centers also give certain generators a signal that supplements primary generator controls and enables the system to match small changes in load and meet the scheduled power exchanges with neighboring systems. This control mechanism is called automatic generation control.

In addition to these functions, the long-term health of the system is a separate concern that planners at utilities and system operators generally address through appropriate mid- and long-term planning. However, this chapter focuses on transmission operations rather than on planning. Further discussion of transmission planning policy issues can be found in Chapter 4.

A summary of the various generation and transmission operations and planning functions organized by timescale is presented in Figure 2.1. Currently, system control centers are supported by supervisory control and data acquisition (SCADA) systems that report the status of circuit breakers—open or closed—as well as voltage, current, and power levels. Devices called remote terminal units (RTU) located at generators and substations collect this information and send it to the control center every few seconds. Remote terminal units also may receive commands, such as an instruction to open or close a breaker, from system operators. The typical response time for SCADA systems today is several seconds, but some power system phenomena occur in fractions of a second. Important emerging technology, discussed in Section 2.3, has the potential to give operators insight into these faster dynamics.

Figure 2.1 Transmission Operation and Planning Functions by Timescale



Source: I. J. Perez-Arriaga, H. Rudnick, and M. Rivier, "Electric Energy Systems: An Overview," in *Electric Energy Systems: Analysis and Operation*, eds. A. Gomez-Exposito, A. Conejo, and C. Canizares (Boca Raton, FL: CRC Press, 2008), 60.

Note: AGC = automatic generation control.

Transmission Reliability

Reliability is and will continue to be a dominant constraint in transmission planning and operations, but as discussed in Chapter 1, it is difficult to measure. Available data is insufficient to make conclusions about long-term trends in reliability of the U.S. transmission network. The North American Electric Reliability Corporation (NERC) and the U.S. Department of Energy (DOE) gather data on NERC-defined "major events," but these events do not necessarily affect customers.[iv] NERC has begun to improve its practices for gathering and reporting reliability data in the last decade in response to the August 2003 blackout and subsequent legislation. However, much of the new data has been gathered for just a few years or less, not long enough to perform a good evaluation. The most recent and comprehensive report on these positive efforts is the 2011 Risk Assessment of Reliability Performance.[4]

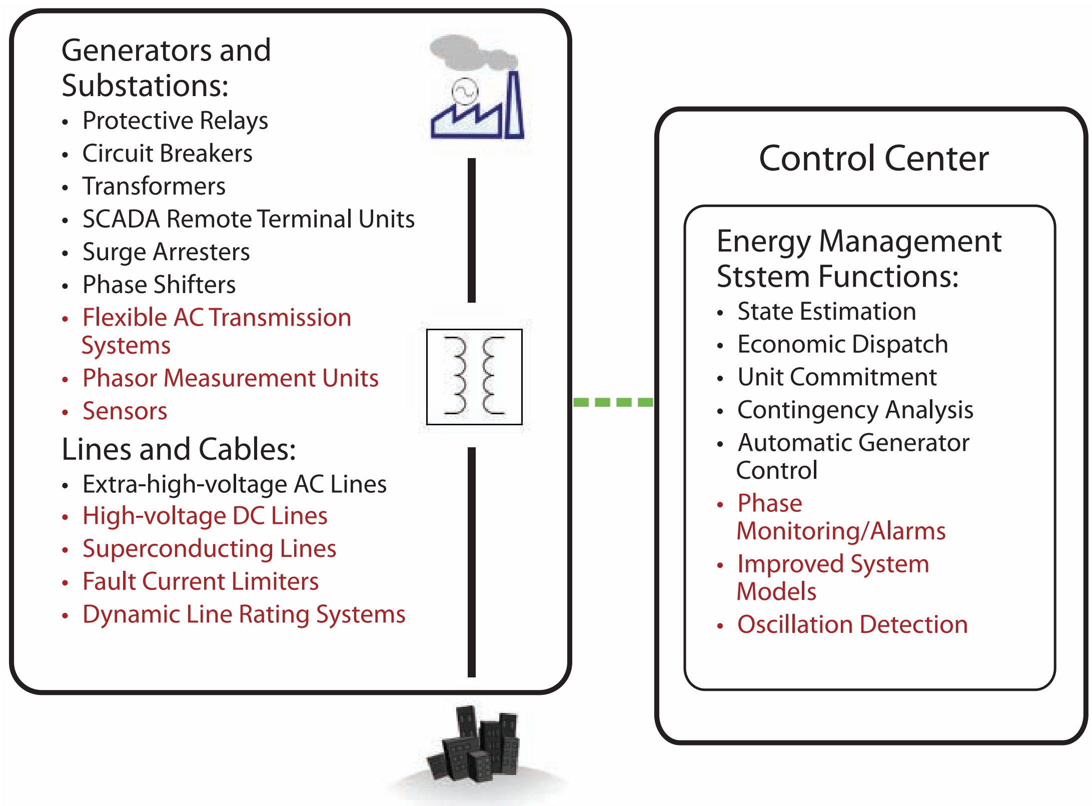
FINDING

Comprehensive and accurate data for assessing trends in the reliability of the U.S. transmission network are not available.

Although it is difficult to measure, the reliability of the U.S. transmission grid clearly faces challenges along three dimensions: anticipating and preventing blackouts; increasing transmission capacity with low environmental impact; and improving system operations, especially to incorporate variable energy resources, such as wind and solar power. Figure 2.2 lists technologies and functions to address these challenges and shows how they fit into the power system. Existing technologies and functions, such as circuit breakers, transformers, and state estimation, are shown in black. Important new technologies and functions, discussed in the remainder of this chapter, are shown in red. Such lists of new technologies have been compiled and discussed elsewhere; for example, the Electric Power Research Institute (EPRI) has performed an analysis of costs and benefits of various technologies[5] and in Europe, transmission operators, equipment manufacturers, universities, and other stakeholders have put together a roadmap of innovative transmission technologies.[6] This figure is meant as a reference for the set of technologies discussed in this chapter, not a comprehensive list of transmission technologies and functions.

[iv] For example, any loss of generation greater than 2,000 megawatts in the Eastern or Western Interconnection and 1,000 megawatts in ERCOT must be reported, regardless of whether the loss of generation affects customers.

Figure 2.2 Transmission Network Technologies and Control Center Functions



Note: Existing technologies and functions are listed in black; new and emerging elements are shown in red.
SCADA = Supervisory control and data acquisition.

2.2 PREVENTING BLACKOUTS

While major blackouts occur only rarely in the U.S., they have serious economic and social consequences. The largest blackout in North American history occurred in 2003, affecting 50 million customers in eight northeastern states and Ontario. The second largest, in 1965, affected 30 million customers. Both blackouts were the result of cascading failures of the power system, in which seemingly small and localized problems caused the system to become unstable and subsequently affect a much wider area. Preventing such blackouts is an important goal that requires monitoring the state of the power system (see Box 2.1). Wide-area measurement systems (WAMS) allow such monitoring to occur on a larger scale than previously possible, enabling system operators to better protect against the most catastrophic class of blackouts. WAMS consist of measurement devices, communications networks, and visualization software; the most critical is an enabling technology called the phasor measurement unit (PMU).

While major blackouts occur only rarely in the U.S., they have serious economic and social consequences.

PMUs measure defining characteristics of voltages and currents at key substations, generators, and load centers, such as cities. System frequency and other quantities often also are measured. Taken together with known line characteristics, these measurements can be used to calculate instantaneous power flows throughout the system.

PMUs report data much more frequently than do SCADA systems, which results in higher-resolution information about system dynamics. Industry standards require that PMUs have a reporting rate of 30 times per second, and many devices are capable of even higher rates. Critically, measurements from all PMUs can be synchronized using GPS time signals, enabling more accurate characterization of system-wide dynamics.

WAMS are currently deployed in many areas, but their usefulness has historically been limited by the small number of accompanying PMUs and software programs to process the raw PMU data. As of early 2010, approximately 250 PMUs were deployed across North America, with more than 850 additional PMUs scheduled to be added between 2010 and 2013 through projects funded by the American Recovery and Reinvestment Act of 2009.[7] Software applications to aggregate and analyze the PMU data and produce actionable information for system operation or planning are critical to realizing the full benefits of PMUs. However, they remain relatively undeveloped today. One such proposed tool is a monitor or alarm that would warn when the voltage phase angle differences between different locations on the transmission network stray beyond predictable ranges, indicating that the system is under stress. The concept of phase angle difference is discussed in more detail in Box B.1 in Appendix B.

BOX 2.1 ESTIMATING THE STATE OF THE POWER SYSTEM

The voltages, currents, and power on all the lines in transmission systems are under continuous monitoring by system operators. These data are used in models of power systems that include the lines, generators, and loads. These models are known as state estimators, and their output is the estimated system state. The state of a power system is a snapshot of the system voltages and currents at one time that operators use to assess the condition of the system and, if needed, take action. For example, operators may use the model results to identify anomalous system conditions, dispatch generation, and avoid stability and thermal limits.

As with any model, the result of the state estimator is only an approximation of the actual system state. One reason is that sensor measurements from the supervisory control and data acquisition system are not sent at the same instant; data may be spread over a period of several seconds, and thus phase angle data cannot be observed. Another is that these data are not always precise. State estimators address these issues by exploiting the redundancy of measurements throughout the system.

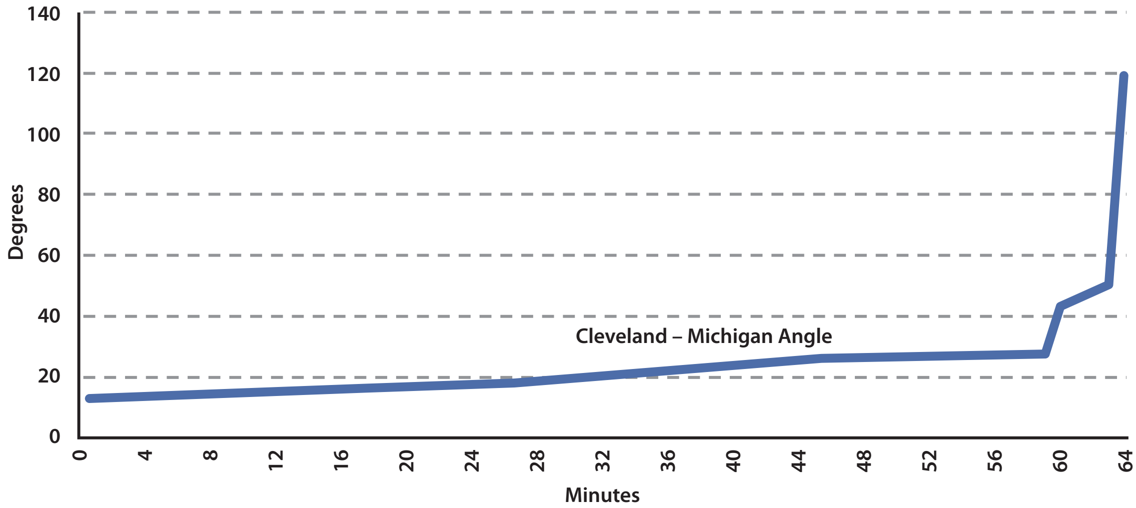
State estimators use an iterative algorithm, and the estimated system state is obtained after several attempts to converge on a solution. The algorithm is not perfect, and state estimators have trouble estimating a system state during unusual or emergency conditions—unfortunately, when they are most needed.

The usefulness of phase angle alarm applications is illustrated in Figure 2.3, which shows the phase angle difference as a function of time between Cleveland and Michigan leading up to the 2003 blackout. Analysis of phase angle measurements revealed a slow divergence nearly an hour before the start of the blackout. Had the PMUs been networked and a real-time phase angle monitoring application been in use at the time, system operators would have had more warning of the impending problem and an opportunity to take remedial action.[8]

The development of phase angle alarms is not trivial. Baseline data must be collected from PMUs over a minimum of several years before alarms or other useful applications can become operational, and these data must be shared with all relevant stakeholders. Only a few early phase angle alarms have been implemented; for example, the Bonneville Power Administration has had a system in operation long enough to establish a baseline for the phase angles at three of its hydroelectric generators. Obtaining baseline data through observation is an important prerequisite for not only phase angle alarms but also for many other potential software applications of synchronized phasor measurements.[v]

To facilitate sharing of synchronized phasor data between regions, NERC created two nondisclosure agreements in February 2010. One agreement is meant for industry entities and covers the confidential sharing of phasor data within the NERC phasor community for operational and reliability purposes. The second agreement covers the sharing of industry phasor data with researchers on a restricted basis for the benefit of the industry as a whole.

Figure 2.3 Cleveland–Michigan Phase Angle Difference Leading Up to the August 2003 Blackout



Source: North American Electric Reliability Corporation Real-Time Application of PMUs to Improve Reliability Task Force, *Real-Time Application of Synchrophasors for Improving Reliability* (Princeton, NJ, 2010), http://www.nerc.com/filez/rapirtf.html.

[v] One other specific benefit of synchronized phasor measurements is mentioned in the next section on increasing transmission capacity.[9]

It remains to be seen whether these agreements will prove effective. As of September 2011, only a limited number of entities had signed these data-sharing agreements.[10] A further concern is that the agreements cover only sharing of measured data, but in order to effectively use the data, information about the underlying network is also required.

These concerns do not warrant immediate action because the agreement is still relatively new, and sufficient sharing of network models may occur organically over time between system operators and some trusted academic research institutions. However, policy makers should be cognizant of this potential research bottleneck.

FINDING

Phasor measurement units have the potential to greatly benefit the transmission network. However, mechanisms for sharing data are immature, and many tools for data analysis have yet to be developed.

2.3 INCREASING TRANSMISSION CAPACITY

As load centers grow and generators are built in new locations, the transmission network's capacity must be enhanced to reliably and economically connect the two. The primary tool applied to this task is the construction of new transmission lines, for they are the fundamental building block of the transmission network. Building new transmission lines can be difficult. New rights-of-way—the land on which lines are built—are very difficult to obtain for political and environmental policy reasons. Projects can stretch over many years, delaying needed network reinforcements. And even planning new transmission lines—a subject covered in more detail in Chapter 4—is complex and requires balancing the details of local transmission networks with long-term strategic regional and interregional objectives.

In this section, we first discuss the fundamental physical characteristics that impose limits to transmission capacity. Next, we present transmission line technologies that can increase capacity. These include extra-high-voltage (EHV) ac and high-voltage direct current (dc) lines, high-voltage transmission overlays, underground cables, and superconductors. Finally, we discuss the potential of PMUs and dynamic line rating (DLR) systems to increase transmission capacity in some situations without building new lines, though these are not long-term substitutes for new infrastructure.

Transmission Capacity Limits

There are three primary constraints on the capacity of a transmission line: the thermal constraint, voltage stability, and transient stability. The first, the thermal constraint, is straightforward. The losses in a line increase its temperature, which in turn causes the line to stretch and sag between supports. At some maximum temperature, or thermal constraint, the sag is sufficient to reduce the line's clearance from ground to a minimum acceptable value.

There are three primary constraints on the capacity of a transmission line: the thermal constraint, voltage stability, and transient stability.

Stability limits are more complicated than the thermal constraint and derive from considerations discussed in Box 2.2. These limits are reached when operators are concerned that an unexpected event might cause system instability. To determine these stability limits, operators must perform an extensive analysis known as an N-1 contingency analysis. It is clear that for any set of normal system conditions, power flows must not cause overheating or system instability. N-1 contingency analysis takes this one step

BOX 2.2 POWER SYSTEM STABILITY

Stability of an alternating current power system refers to its ability to maintain synchronous operation after being subjected to a disturbance. Instability can lead to major negative consequences, from localized power interruptions to widespread blackouts. In general, adequate reserve generation, transmission capacity, and tightly meshed networks contribute to a stable system.

Two of the main forms of stability that concern system operators and planners are transient and voltage stability. They are interrelated, and stability problems of one sort usually give rise to others. Stability classifications are based on the physical nature of stability phenomena, the system variables where that stability phenomena are observed, and the methods of analysis that must be used to address the stability issues.

Transient stability refers to the ability of a transmission line to accept a transient increase in power flow without exceeding the maximum safe voltage angle between the ends of the line.

Voltage stability refers to the ability of a power system to maintain acceptable voltage levels across the network after a disturbance. The most common form of voltage instability is a progressive drop in voltages following a disturbance when the automatic controls associated with some loads push generators and transmission equipment beyond their capabilities.

The description of stability here is a considerable simplification of the precise industry standard classifications, which include several other types of stability. A comprehensive description can be found in P. Kundur et al., "Definition and Classification of Power System Stability IEEE/CIGRÉ Joint Task Force on Stability Terms and Definitions," *IEEE Transactions on Power Systems* 19 (2004): 1387–1401.

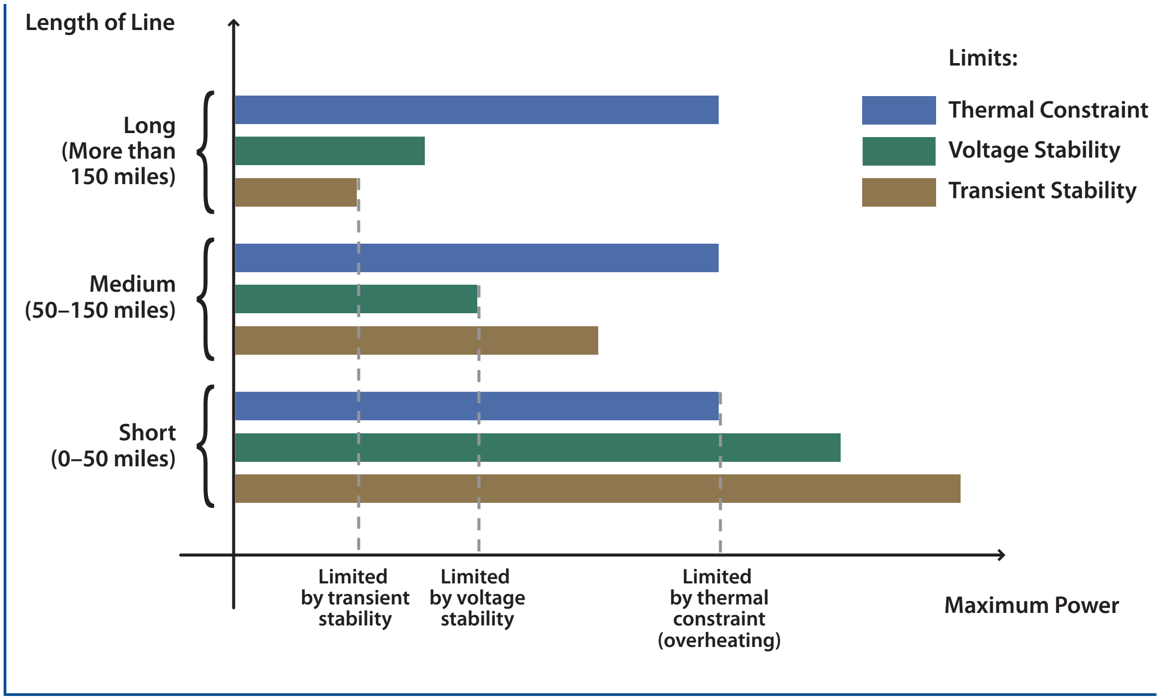
further to ensure that even if any single major system component (such as a large generator or transmission line) is unexpectedly lost, the power flows on network lines still do not violate these limits. Due to the large number of possible situations under which contingencies might occur, this analysis requires expert judgment, time, and computational power.

Figure 2.4 illustrates the typical limiting factors on the power transfer of short, medium, and long lines. The thermal limit has to do with material properties of the line and is constant no matter the length of a line. Since stability is a system property rather than a material property, stability limits change depending on the length of a line and other system conditions. Thermal considerations generally limit power transfer on short lines, while longer lines tend to be stability limited. In particular, power transfer on medium-length lines is usually constrained by voltage stability, while the longest lines are limited by transient stability.

Long-Distance Transmission Technologies

Challenging these physical constraints is increasing political interest in integrating variable energy resources, such as wind and solar, into the grid. These energy resources have gained favor at the federal and state levels, but they are often distant from load centers. The technical capability exists to provide long-distance transmission, but the benefit of access to distant renewable resources must be balanced with the higher cost and difficulty of siting such lines. Striking the proper balance in transmission for distant renewable generation sources is a difficult problem to be addressed through transmission planning policy and regulation, discussed in Chapter 4. Here we discuss the two technologies appropriate for long-distance transmission—extra-high-voltage ac and high-voltage dc, two relatively mature technologies.

Figure 2.4 Three Primary Constraints of Transmission Lines



EHV ac transmission systems have voltages greater than 242 but less than 1,000 kV. The highest in commercial operation in the U.S. is 765 kV, while 345 kV and 500 kV are standard voltage levels.[11] Higher voltage transmission lines have been installed in China, Russia, and Japan, but only China operates its 1,000 kV system at its rated voltage.[vi, 12] Compared to their lower-voltage counterparts, such lines are capable of transmitting more power over longer distances but require larger, more expensive transformers, insulators, and towers, as well as wider rights-of-way. As a result, the highest-voltage ac lines are most economical for large-capacity, long-distance electricity transmission. Installing high-voltage, large-capacity links can improve reliability by allowing neighboring areas to support one another and improving stability characteristics of the network. The length and capacity of a long EHV ac line is typically limited by stability considerations—the longer the line, the lower the capacity limit, though the effective length of lines may be extended by installing voltage support equipment.

The transmission system consists mainly of ac lines due to their many desirable characteristics, such as the ease of voltage transformation. However, dc lines can be valuable additions to ac transmission networks. High-voltage dc lines are not limited by stability considerations and therefore theoretically are not limited in length. Conductor costs—the cost of the metal which conducts electricity—for dc transmission lines are lower than for ac lines of the same voltage because fewer conductors are necessary and conductor utilization is better. But the cost for dc substations is significantly higher because transformers only work for ac, so more

Dc lines can be valuable additions to ac transmission networks.

[vi] Russia and Japan now operate their 1,000 kV lines at 550 kV.

expensive power electronics converter stations are required to convert between ac and dc. And tapping a dc line—that is, connecting a load in the middle of the line—requires a costly and complex converter station instead of a much less expensive transformer as for an ac line.

The electrical losses in an ac/dc converter station are higher than in an ac substation. A rough rule of thumb is that for high-voltage ac lines, total substation losses are approximately 0.5% of rated power, while combined converter station losses from both ends of a traditional high-voltage dc line are approximately 1.5%.[13] However, the losses per mile of a dc line are lower than those of an ac line. Thus, dc is especially suited to long-distance, point-to-point power transmission, where a single generating site connects to a single point on the ac grid.

In the U.S., the ±500 kV Pacific DC Intertie stretches nearly 850 miles from Oregon to Los Angeles; China's ±800 kV dc link from the Xiangjiaba Dam to Shanghai is nearly 1,300 miles long and currently the world's longest and highest-voltage dc link.[14]

One analysis of hypothetical transmission projects compared the cost and electrical losses of 765 kV ac to ±800 kV dc for a 6,000 megawatt transmission link at different distances.[15] For an 800-mile link, the analysis found that electrical losses of the 765 kV ac line at full load would be nearly double those of a ±800 kV dc line and that the up-front cost to build the 765 kV ac line would also be approximately double the cost of the ±800 kV dc line. If the project were a line of only 200 miles, however, the dc option would be slightly more expensive and have approximately the same losses. This case is merely illustrative of the relationships between length of lines and cost/losses of high-voltage ac and dc transmission projects; any real project would be evaluated in a more detailed fashion on many more important criteria, such as long-term system impact on reliability and right-of-way considerations. The least-expensive option is not necessarily the most appropriate.

FINDING

Where long distances separate renewable resources from load centers, dc transmission lines may be economically attractive.

A newer version of high-voltage dc converters known as voltage source converters (VSC) offer the potential for improved system stability and control.[16] And unlike conventional high-voltage dc, VSCs do not require strong ac generation sources at both ends of the line, making it more attractive as a technology to connect variable energy resources. These benefits are made possible by a more flexible type of switch that is used in the converter—a transistor rather than a thyristor.[vii] A dc mesh network using VSC high-voltage dc is envisioned to connect dispersed wind generators in the North Sea with several areas of mainland Europe.[17] So far, this technology has not achieved the highest voltages attainable by traditional high-voltage dc: the highest-voltage link in operation as of 2011 is the ±350 kV Caprivi Link connecting Zambezi and Gerus in Namibia; the capacity of this link is only 300 MW, but new advances in semiconductor devices and dc circuit breakers promise to allow higher voltage levels and capacities within the next few years.[18] VSC high-voltage dc converter stations have somewhat higher energy loss than conventional high-voltage dc stations, though the efficiency of VSC converters is also improving.

[vii] The transistor and thyristor are both semiconductor devices that function as a switch, but they have different characteristics. Thyristor switches can be turned on easily but may only turn off under certain conditions. Transistor switches can be turned on and off easily.

FINDING

The control flexibility of voltage source converters can improve system stability and facilitate the integration of remotely located renewable generation.

Transmission Overlays

In recent years, proposals have been made for high-voltage transmission overlays—a new network of EHV transmission lines superimposed on the existing transmission network.[19] Such transmission overlays could create a more tightly meshed network spanning a large geographic area to facilitate the integration of variable energy resources. However, the benefits of such an overlay, described here, must be valued against the very high cost of constructing such an extensive transmission network, a cost that we do not presume to estimate.

A transmission overlay undoubtedly would have many benefits, including access to better sources of renewable energy, improved reliability, and lower losses. As the U.S.–Canada Power System Outage Task Force notes, "higher voltage lines and more tightly networked lines…are better able to absorb voltage and current swings and thus serve as a barrier to the spread of a [cascading failure]."[20] For a given level of power transmission, losses decrease when voltage is increased, and optimally loaded lines have lower losses than overloaded lines. It is also possible that stronger ties between areas would allow system operators to reduce requirements for costly reserves.

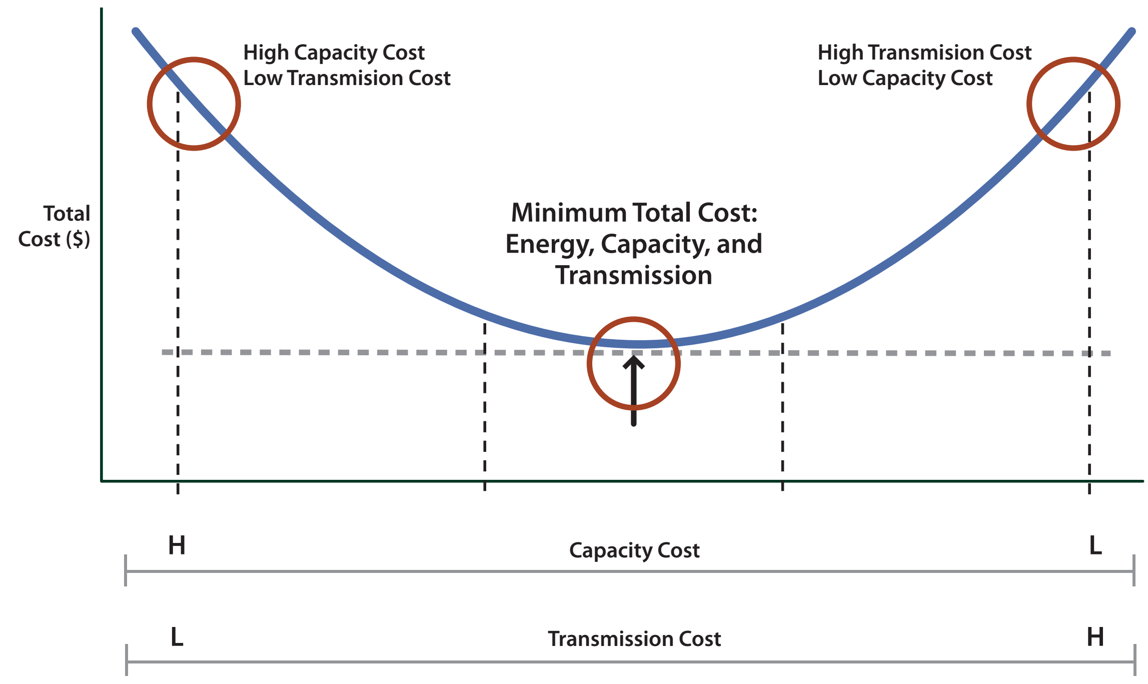
But building a network of high-voltage lines is also costly. Evaluating the full range of costs and benefits of a transmission overlay requires the sort of interregional planning process described in Chapter 4. The Midwest ISO's Regional Generation Outlet Study is an example of a successful system planning exercise at the regional level.[21] The purpose of the study was to support development of transmission portfolios fulfilling the region's renewable portfolio standards at the lowest cost per delivered megawatt hour. These standards dictate that a certain percentage of energy is generated from renewable resources. One key consideration noted in this study is the balance between low transmission costs for wind resources local to load centers and favorable capacity factors of wind resources distant from load centers. This trade-off is illustrated in Figure 2.5. Through detailed analysis of the particular characteristics of the Midwest region, this study concluded the optimal solution to be a transmission overlay serving wind zones of both types, rather than only one or the other: some local wind resources and some distant. Based on this conclusion, the study went on to analyze transmission overlay options and identify a set of promising transmission projects to be used as inputs in the Midwest ISO's transmission planning process.

As noted in Chapter 4, planning processes for interregional areas face both technical and institutional challenges. Interregional renewables integration studies, such as the Eastern Wind Integration and Transmission Study and the Western Wind and Solar Integration Study have shown that integrating high penetrations of renewables is technically feasible through higher-voltage, tightly meshed transmission lines, but a true plan has yet to emerge.[22]

FINDING

Creating a high-voltage transmission overlay is technically feasible and would benefit system operations and facilitate the interconnection of renewables. In the absence of detailed inter-regional planning studies, the features and costs of an optimal future overlay network remain uncertain.

Figure 2.5 Trade-off between Transmission Cost and Capacity Factors



Source: Midwest Independent System Operator, *Regional Generation Outlet Study* (Carmel, IN, 2010).

Underground and Submarine Transmission

Underground or submarine cables are used in locations where overhead lines are impossible or undesirable. A severe constraint when these cables are used for ac transmission is that the high capacitive charging current required generally limits their length to just tens of miles. Dc cables are limited only by electrical losses; the longest submarine dc cable is a 580 kilometer link between Norway and the Netherlands. Despite innovations in insulation materials, the complexity of assembling and installing cables means that cables will remain more expensive than overhead lines.[23] However, the difficulty of siting overhead lines in the U.S. can make underground and submarine cables an attractive option in some areas despite the greater expense.

Superconductors

High-temperature superconductors (HTSCs) have emerged from the research labs within the past decade. Superconductors are materials that have extremely low electrical resistance when cooled below a certain critical temperature, which is different for each superconductor. HTSCs are those that may be cooled using liquid nitrogen, a relatively inexpensive coolant with a boiling point of -196°C. They have a much higher power capacity compared to normal conductors of the same physical size, but are constrained by the difficulty of maintaining adequate cooling. The longest, highest-capacity HTSC cable to date, operating at 138 kV ac, was successfully demonstrated in 2008 with the help of government funding.[24] This project connected two substations separated by 600 meters in the Long Island Power

Authority service territory and overcame several practical technical challenges of superconducting transmission lines, such as the ability to withstand fault currents—abnormally high current levels caused by short circuits on a transmission line. A second stage of this project is under way that will test rapid field repair of the refrigeration system and the ability to make joints between cable sections.[25] High-temperature superconductors are becoming more practical as an option for increasing the capacity of existing cables by replacing them with ac HTSC cables in the same conduits. This is particularly attractive where the cost of conventional alternatives is high, such as in dense urban areas.

Superconductors also may be used to create a device called a fault current limiter (FCL). As its name implies, the purpose of an FCL is to reduce the amount of current that flows under fault conditions—not by isolating it through switches but by introducing a high impedance to reduce the level of current. On some lines, adding an FCL can allow heavier line loading without exceeding the capacity of circuit breakers. Since high impedance is not desirable under normal system conditions, the challenge in designing an FCL is how to insert impedance in the system extremely quickly only when it is needed, under fault conditions. In the case of one simple superconducting FCL design, the impedance is inserted by exploiting the natural limits of superconducting materials. Above some maximum current level, the material reverts from superconducting behavior to a normal conductor having high impedance. While promising, superconductor FCLs have not yet been demonstrated at transmission-level voltages,[viii] though at least two projects hope to achieve this goal within the next two years.[26]

FINDING

HTSC cable technology has been demonstrated as practical and is a promising approach to substantially increasing the capacity of existing cables without the need for new rights-of-way.

Phasor Measurements for Increased Transmission Capacity

In addition to helping prevent blackouts, synchronized PMUs can potentially improve system capacity by allowing operators to take the grid closer to its true stability limit, effectively increasing capacity of some lines without increasing the risk of a blackout. In an early example, an agreement between the California ISO and NERC to share synchronized phasor data is expected to eventually result in a 30% increase in the capacity of the California–Oregon Intertie.[27] Such large increases are not expected to be common because only stability-limited lines have the chance to benefit from the synchronized data. However, increases in the capacity of only a few key transmission lines could result in large economic benefits.

Increases in the capacity of only a few key transmission lines could result in large economic benefits.

Dynamic Line Ratings

Dynamic line rating systems also potentially can increase the operational capacity of transmission lines. Historically, system operators have established the thermal limits of lines under seasonal worst-case assumptions; a hot, windless day is an example of a worst-case scenario in the summer. This static limit is often conservative relative to actual conditions. DLR systems measure changing environmental

[viii] This is also true of FCLs constructed by other means, such as using power electronic devices.

conditions and update system models accordingly, increasing transmission capacity limits in all but those few worst-case scenarios. Though dynamic line rating systems can be implemented with a variety of sensors, one design deployed relatively widely today uses just two, one to measure line tension and another to measure air temperature. These two pieces of data allow operators to determine average conductor temperature, the main determinant of a line's thermal limit. DLR systems installed on existing transmission lines have been shown to improve the capacity by 5%–30% depending on conditions.[28]

Dynamic line rating systems installed on existing transmission lines have been shown to improve the capacity by 5%–30% depending on conditions.

DLR systems are particularly attractive in the case of transmission lines linking wind generators to the rest of the transmission network. Wind generators require more transmission capacity when the wind is strongest; conveniently, strong winds are precisely the conditions in which DLR systems improve transmission capacity. However, where wind resources are far from load centers, the long connecting lines needed would tend to be limited by stability rather than thermal properties. DLR systems will not improve the capacity of these lines.

In some extreme weather situations, DLR systems will place more restrictive limits on transmission capacity than traditional static line ratings. Knowledge of true transmission capacity limits means improved reliability at the most critical times of extreme weather, when electric loads are high and systems are their most stressed. This was the case during the 2003 blackout, when static transmission capacity limits for some lines had been set assuming a modest amount of wind would cool wires, when in fact there was hardly any wind.[29] A DLR system would have provided another layer of warning to system operators.

Because a survey of electric service providers in 2009 revealed that only 0.5% of respondent's lines were equipped with DLR systems, DOE has classified the penetration of these systems as "nascent."[30] Based on the positive results of previous deployments, we can expect an increase in penetration of DLR systems between now and 2030.

2.4 IMPROVING SYSTEM OPERATIONS

The challenges of intermittent generation (Chapter 3) and opportunities for advanced demand response schemes (Chapter 7) will create opportunities for technological change in system operations. Notably, energy management systems will need upgrades to accommodate synchronized measurements from PMUs. And power electronics devices, supported by these synchronized measurements, could play a role in advanced control schemes requiring novel communications architectures. The control systems of the future are less understood than many individual technologies discussed in this chapter and should be the subject of R&D efforts by utilities and academic institutions.

Energy Management Systems Integrating PMUs

Energy management systems must be updated if they are to process the additional data available from PMUs. Adding synchronized phasor data to existing state estimators can improve accuracy of the estimated state, resulting in more optimal economic dispatch of generating units. However, these improvements are incremental and do not address the fundamental shortcoming that state estimators sometimes fail when system conditions are unusual. Eventually state estimators could be partially replaced by aPMU-based tool yet to be developed that directly measures

The control systems of the future are less understood than many individual technologies.

rather than estimates system state. Such a tool would be faster and potentially more accurate than state estimators today, and would avoid the problems state estimators have finding a solution during unusual system conditions. This tool would require PMUs to be deployed very widely, at perhaps 30%–50% of all nodes.[31] Concerns about the reliability and accuracy of PMU measurements for critical applications would also need to be addressed. Given the number of PMUs being deployed today, such a system might be feasible only at the highest voltage levels by 2030 and, if developed, would likely supplement rather than replace current state estimators.

FINDING

PMUs could improve the performance of energy management systems by providing real-time data to determine system state faster and more accurately than currently employed state estimation tools. A more extensive deployment of PMUs is required to make this possible.

Advanced Control Schemes

Increased computational power and the availability of more accurate and timely data make possible new approaches to system control. Among these are more sophisticated protection actions, wide-area control systems, and closed-loop control using PMU data.

The most complex control schemes deployed today are called system integrity protection schemes (SIPS),[32] which are comprised of decentralized subsystems that make decisions based on local and wide-area measurements.[33] These system-wide SIPS are normally implemented in cases of large power transfers between regions, when exceeding that line's capacity rating could potentially trigger a catastrophic blackout. In the U.S., system operators primarily in the Western Interconnection have implemented some SIPS. Where a typical protection system would simply isolate the offending line by tripping circuit breakers at either end—potentially sending shock waves through the rest of the system—SIPS use precalculated scenarios to coordinate more intelligent responses. Such responses can include intentionally islanding the two regions,[ix] shedding load, or activating voltage support devices.

Eventually, PMU-supported WAMS could be transformed into wide-area control systems that actively participate in control actions.[34] The concept encompasses a broad range of possible future control schemes. On the one hand, wide-area control could be nothing more than what SIPS are today: protective procedures developed to respond to a specific type of problem. On the other hand, wide-area control could also use closed-loop feedback control to stabilize detected system oscillations.

As these research efforts bear fruit and new tools become available to system operators, control room visualization techniques and operator training will become increasingly important. The control room is already enormously complex, and in a crisis, operators must quickly assimilate a staggering amount of information. Additional tools in the control room must not simply make new information available to operators, but present old and new information in more effective ways. Additionally, operators must train extensively on new tools before they become operational; as a result, new

[ix] An island in this context is a self-contained section of the network, within which load and generation are balanced. Determining where such islands might be created to aid system stability requires careful study of system contingencies, and creating such an island involves switching many circuit breakers and also likely shedding some amount of load within the island to balance load and generation.

NERC standards require a more systematic approach to training than did previous standards.[35] Training includes general familiarization in combination with detailed simulations of potential crises that might occur. The resources and time required to develop appropriate visualization tools and prepare operators to use them should be incorporated into R&D strategies for integrative control systems.

FINDING

Automatic control action based on real-time data from a wide-area network of PMUs represents a major change in system operations. Today, such systems are limited in number and capability. Significant research in control algorithms and improved confidence in the reliability and accuracy of PMU data is needed to make such controls more prevalent.

Flexible Ac Transmission Systems

A critical piece of the advanced control schemes envisioned for the future is FACTS. These employ power electronics that are connected to the transmission network to enable more rapid and flexible control of the system. The basic characteristics of several FACTS devices are summarized in Table 2.2. Each of the devices listed in the table has been deployed on real transmission systems. However, the deployment of devices other than SVCs has been limited because of cost. Integration into more sophisticated control systems could help justify these high costs in some situations.

R&D efforts to reduce costs will be necessary if FACTS are to become a significant factor in power systems of the future. Research on FACTS can be divided into three categories: semiconductor materials, control algorithms within individual FACTS devices, and system-wide control schemes incorporating FACTS. More work is needed in all three areas, but the last two categories are particularly important. Work is also needed to develop strategies to replace highly specific control algorithms, which become obsolete with changes to the transmission network, with algorithms based on a reconfigurable architecture. Research collaborations among system operators, academic institutions, and equipment vendors should be encouraged.

FINDING

To fully realize the improved system benefits of synchronized phasor data, FACTS devices, and other new technologies, control systems leveraging the complementary features of these technologies need to be developed.

Table 2.2 Summary of Main FACTS Devices

<table>
<tr><th>Name</th><th>Most Suitable Functions</th></tr>
<tr><td>Static VAR Compensator</td><td rowspan="2">Control voltage level at nodes
Improve system stability characteristics</td></tr>
<tr><td>Static Synchronous Compensator</td></tr>
<tr><td>Thyristor-Controlled Series Compensator</td><td>Improve system stability characteristics
Control flows of power</td></tr>
<tr><td>Unified Power Flow Controller</td><td>Control voltage level at nodes
Control flows of power
Improve system stability characteristics</td></tr>
</table>

Information and Communication

New communications infrastructures[x] and architectures will support power system operations in the future. Many methods of data transmittal are used for various communication tasks on the power system today; radio, microwave, power line carrier, and fiber optics are some of the more common media. To accommodate the high bandwidth, latency, and reliability needs of future software applications, fiber optics likely will become more prominent.

One visualization system has begun to show the potential of leveraging modern communications infrastructure to the direct benefit of electricity customers. The Energy Awareness and Resilience Streaming Service (EARSS) was developed at Oak Ridge National Laboratory and draws on data reported by multiple utilities to provide up-to-date information on both the transmission and distribution systems across multiple jurisdictions. The system was used to support emergency and recovery efforts during and after Hurricane Irene in August 2011, a significant improvement over information available during the August 2003 blackout.[36]

More disruptive changes could occur in the architecture of the communication system. Today, most system operational decisions take place at the control center based on data gathered through the SCADA system. Some researchers envision an IT framework that allows different groups of stakeholders to gather information and make intelligent operational decisions autonomously.[37] For example, an electricity customer might have access to information about the price of electricity or other aspects of system status and optimize electricity consumption based on this greater knowledge. Among other things, this would require more seamless sharing of information between transmission and distribution system operators. The big challenge for regulators in deciding whether operators should cede some control to other stakeholders is how to maintain and guarantee the same high level of reliability.

Some researchers envision an IT framework that allows different groups of stakeholders to gather information and make intelligent operational decisions autonomously.

New tools for system operations will be supported by gains in the processing power of computers and new algorithms to take advantage of such gains. Over the past decade, PJM has led an effort to develop and implement new optimization algorithms to help solve the problem of how many generator units to commit each day, and when to commit them. These efforts have resulted in considerable cost savings in several U.S. electricity markets.[38] New approaches to other optimization problems in system operations might result in further substantial savings. For example, recent work has explored the possibility of optimizing transmission switching—adding or removing lines from the transmission network using switches—along with generator production in power flow models.[39]

2.5 CONCLUSIONS AND RECOMMENDATIONS

As noted in Chapter 1, the transmission network today operates reliably and efficiently. But new technologies are available that can improve system performance, offering enhanced reliability, increased capacity, and the ability to better accommodate VERs. No single technology, acting alone, is likely to have a significant impact. However, the combination of multiple technologies into an integrated system of sensors, communications

[x] Chapter 9 is devoted to issues surrounding communications, data security, and privacy.

infrastructure, control equipment, and intelligent management systems will provide significant benefits.

PMUs integrated into wide-area measurement systems with appropriate analysis tools that turn the measured data into actionable information could provide protection from blackouts and increases in system capacity. While PMU hardware exists, and is being installed more widely as a result of ARRA funding, the software and analysis tools necessary to fully capitalize on this investment are yet to be developed and deployed.

Greater control of system voltages and power flow can be achieved through the more extensive deployment of FACTS devices. The rapid control capabilities of these devices can contribute significantly to network control if integrated with PMUs and wide-area measurement systems. However, the current high costs of the most versatile of these devices is inhibiting their widespread deployment. The integration of FACTS devices with emerging wide-area measurement systems can allow their control capabilities to be leveraged to provide even greater benefits and could make their costs more readily justified.

RECOMMENDATION

Research and development efforts should be undertaken to develop 1) the analysis tools necessary to generate actionable information from data acquired from PMUs and 2) the control schemes necessary to make use of this information by realizing the complementary potential of PMUs, FACTS, and other hardware devices.

More widespread PMU data sharing among utilities, system operators, and researchers is essential to development of the needed tools. Confidential data sharing agreements have been created by NERC, but only a limited number of relevant entities have executed them.

RECOMMENDATION

NERC should continue to encourage relevant entities to participate in PMU data-sharing efforts necessary for the effective development and use of PMUs and wide-area measurement systems.

Although industry has been and continues to be engaged in the development of the technologies discussed in this chapter, their full benefit will occur only if there is greater cooperation among utilities in their deployment.

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Chapter 3: Integration of Variable Energy Resources

In this chapter, we discuss the challenges of operating the grid with high penetrations of wind and solar generation, commonly referred to as "variable energy resources" (VERs). We also present a variety of changes to system operation and planning that can help in meeting these challenges. The chapter provides background on ongoing industry and government efforts to integrate and increase the penetration of VERs, as well as context for later chapters. The topics described in this chapter are of primary interest to industry decision makers.

Section 3.1 describes the basic technical and economic characteristics of VERs and introduces the challenges for the power system derived from the variability and uncertainty of these generation sources. This is followed in Section 3.2 by a discussion of the impact that high penetrations of VERs could have on system operating reserve requirements and several ways to limit system operation cost increases. These include improving VER forecasts and situational awareness, moving generation scheduling decisions closer to real time, and expanding cooperation among neighboring balancing areas. We find that these operational changes will become increasingly important as VER penetrations grow.

Section 3.3 discusses the impact of high VER penetrations on the future well-adapted generation mix and the need to ensure adequate system flexibility. We describe sources of system flexibility, including conventional generation technologies and potential new resources, such as demand response and energy storage.

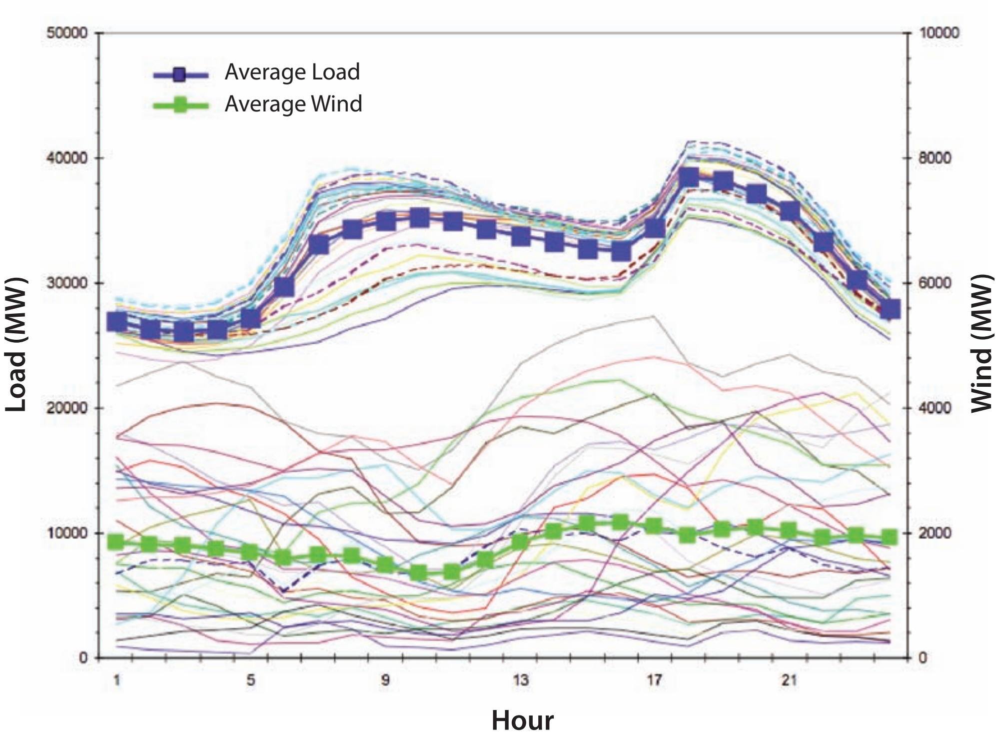
Section 3.4 discusses the critical role of interconnection standards in assuring that reliability is maintained as the penetration of VERs increases. These standards, for both VERs and conventional generation technologies, will need to adapt to the increasing role of VERs. It is particularly important that they be structured in response to anticipated rather than existing conditions.

Section 3.5 gives our conclusions and recommendations. First, we recommend more widespread sharing of granular meteorological data measured at VER sites. Second, we recommend several changes to system operations that could facilitate the integration of VERs in many regions. Finally, we recommend that mechanisms that provide incentives for investment in flexible generation and for operating flexibly be devised and deployed in regions with growing VER penetrations.

Most projections of U.S. electricity production show a substantial increase from wind and solar generation, which are receiving a strong push from state and federal policy through subsidies and renewable portfolio standards. For example, the U.S. Energy Information Administration (EIA) expects renewable sources to constitute 25% of the increase in total generating capacity across the electric power sector between 2010 and 2030.[1]

Commonly referred to as "variable energy resources" (VER), wind and solar power generators are known to be *variable* and *uncertain* because they are subject to only limited control and the energy they produce is less predictable compared to energy from conventional technologies. Variability and uncertainty are familiar concepts in power systems. Through decades of experience, system operators have developed approaches to cope with variability and uncertainty that stem, for instance, from changing demand levels and failures of generation units. But wind and solar generation as new sources of variability and uncertainty present challenges to the operation of the power system.

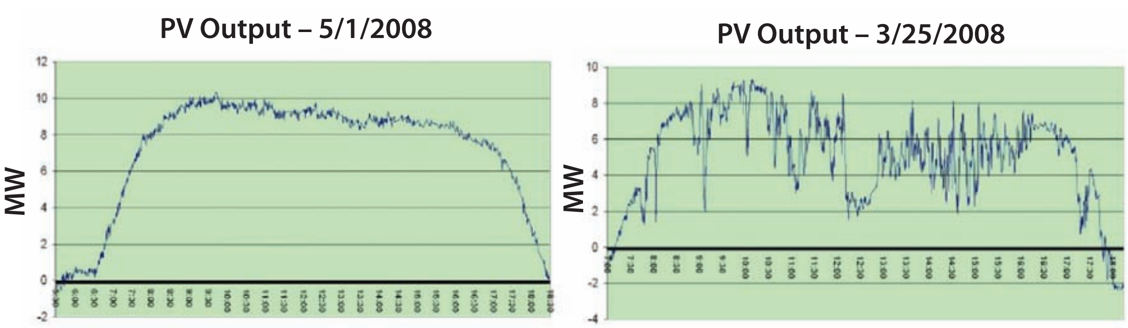
Figure 3.1 Daily Load and Wind Generation Profiles in the California System Compared to Average Profiles for the Month of January 2002



Note: This figure compares daily wind generation and load profiles in California in January 2002. The colored lines in the upper portion of the plot illustrate each individual day's load profile while the lines in the lower half of the plot illustrate each individual day's wind generation profile. The thicker lines indicate the monthly average profiles for load and wind.

Source: GE Energy Consulting, "Intermittency Analysis Project: Appendix B, Impact of Intermittent Generation on Operation of California Power Grid" (Sacramento, CA: California Energy Commission, 2007).

Figure 3.2 Nevada Solar Photovoltaic (PV) Plant Output on a Sunny Day (Left) and a Partly Cloudy Day (Right) in 2008



Source: North American Electric Reliability Corporation, *Accommodating High Levels of Variable Generation* (Princeton, NJ, 2009).

3.1 CHARACTERISTICS OF VARIABLE ENERGY RESOURCES

Figure 3.1, a plot of California's wind generation and its relation to demand, illustrates some of the challenges associated with wind generation. As seen here, wind output can change more rapidly and over a wider range than demand, and it does not conform to daily cyclic patterns. An inverse correlation is sometimes observed in which wind resources on average become most abundant during hours of limited demand at night.[2]

Compared to wind, solar outputs are generally considerably more cyclic and better correlated with load, typically achieving maximum output a few hours before peak demand. However, especially at the individual plant level, solar generation without storage can also produce outputs that are considerably more variable and less predictable than wind. As illustrated in Figure 3.2, individual solar photovoltaic (PV) plants under cloud cover have been observed to vary their outputs by as much as 90% over the course of seconds.

When wind variations or passing clouds result in changes in output, dispatchable generators or loads must make corresponding changes in an effort to balance generation with load over a specific geographic area known as a "balancing region." Larger balancing regions have a greater diversity in VER resource availability and load over wide regions, smoothing out the effects of minute-by-minute variability. Adjacent smaller balancing areas can reap the full benefits of resource diversity by consolidating or cooperating with each other.

Beyond variability, the high uncertainty associated with VER outputs also can complicate existing balancing processes and is often cited as the main source of costs of integrating VER generators into the grid.[3] Since day-to-day wind speeds and cloud cover are significantly less certain than the load forecast, systems with high penetrations of VERs typically must commit more reserve generation than those

The power system must have enough response capacity, from interconnections, demand response, storage, and backup supply to maintain reliability standards.

with low penetrations, which drives an increase in costs. Exacerbating these concerns, large-scale weather events, such as wind storms and wide-area cloud cover, create challenging operational situations known as "ramp events" that are characterized by a significant portion of the VER fleet ramping up or down in unison over a period of minutes to hours. Because ramp events are often difficult to forecast ahead of time, additional reserve generation (or demand response) must be ready to increase production (or decrease load) to meet the load if the VERs ramp down or decrease production if the VERs ramp up. Finally, the absence or very limited presence of the VERs during extended periods of time (e.g. several consecutive days) also can result in operation challenges. The power system must have enough response capacity, from interconnections, demand response, storage, and backup supply to maintain reliability standards under these worst-case conditions.

All the operational adaptations to accommodate VERs require more flexible power systems, incurring operational costs. Fossil fuel plants must bear the expense of additional start-ups and shut-downs, as well as operation at output levels distant from points of optimal fuel efficiency and air pollution control. In addition, more frequent start-ups, shut-downs, and ramping can increase mechanical stress on generation plants, potentially resulting in higher maintenance costs and reduced life.[4] Providing these services at minimum cost while maintaining reliability and system stability requires careful planning of investments, such as the timely addition of dispatchable plants with fast ramping capability.

Beyond the variability and uncertainty of their outputs, wind and solar generation have control and electrical characteristics that are different from those of conventional

BOX 3.1 ALLOCATION OF SYSTEM OPERATING COSTS

The allocation of the increase in system operating costs that results from the introduction of large penetrations of variable energy resources (VER) is a subject of current debate. Historically, the cost of reserves required to reliably operate power systems has been allocated to all end consumers. In a November 2010 Notice of Proposed Rulemaking, the Federal Energy Regulatory Commission (FERC) suggested that VERs be made partly or wholly responsible for the additional costs that they cause.[5]

As with any zero-sum game, it will be difficult to arrive at a mutually agreeable solution, particularly now that the incurred costs are becoming significant. This is exemplified by the responses to the notice.

The respondents to the notice agree that such a cost-allocation scheme for operating reserves will be hard to realize in practice. Regardless, some suggest possible implementations. FERC proposes adding a special ancillary services rate to the transmission access tariffs for VERs.[6] The Federal Trade Commission suggests that each VER plant purchase option contracts on flexible resources that can provide reserves.[7] The Bonneville Power Administration is exploring the possibility of allowing wind generators to pay the cost of their variability by self-supplying the extra electricity to correct any imbalance.[8] This last scheme is in accordance with the design of balancing markets already in place in some European countries.

synchronous generators. Due to their very low penetrations, to date VERs have been required to meet few performance standards in the U.S. As VER penetrations grow, it will become increasingly important that interconnection standards require all generators, including VERs, to play an active role in helping to maintain system stability and reliability under the new anticipated conditions. Because retrofitting generation is typically expensive, it is particularly important that interconnection requirements for all generation technologies, both VER and conventional, be designed for anticipated rather than existing conditions.

VERs historically have affected the U.S. bulk power system very little because they have accounted for only a small fraction of energy supply. However, with significant growth, these policy-backed technologies will require changes to how systems are planned, operated, and controlled. This chapter explores these challenges of system adaptation and the ways that grid management and operation can help minimize the potential grid-related costs of VER expansion. The allocation of the increase in system operating costs that results from high penetration of VERs is also a subject of current debate, as described in Box 3.1.

All the adaptations described in this chapter have been identified and studied in the wind integration literature, and many have been implemented in other countries and in parts of the U.S.[9] Our focus is on wind farms and large-scale PV or concentrated solar thermal installations without storage. We address the implications of large-scale VERs for planning and building transmission systems in Chapter 4, and we discuss the distribution system challenges of distributed generation, usually residential and commercial rooftop PV installations, in Chapter 5.

3.2 VARIABLE ENERGY RESOURCES AND THE COST OF RESERVES

As explained in Chapter 2, generators are initially dispatched according to unit commitment schedules made one day in advance. The unit commitment or day-ahead market process determines which generators will come online or go off-line at various times during the following day. Vertically integrated utilities attempt to minimize the cost of meeting load, subject to transmission line capacity limits and other security constraints, by dispatching generators with lower marginal operating costs before those with higher costs. Where there are organized wholesale markets, system operators utilize generators' bids instead of actual costs in determining how units are dispatched. This process, discussed in Appendix B, is known as "security-constrained economic dispatch." Either by central decision-making or through markets, provisions must be made for the supply of operating reserves and balancing services.

Operators make these scheduling decisions under a level of uncertainty. Since forecasts are never perfect one day in advance, on the day of dispatch, a committed generator may not be needed, or an uncommitted unit might be needed. The committed generators may fail to meet their dispatch schedule due to unforeseen equipment failures or other contingencies, necessitating the dispatch of reserves. Generators and demand response can provide these operating reserves.

Operating reserves are categorized according to the types of events to which they are designed to respond and to the speed, timescale, and direction (up or down) of response expected. In the context of VER integration, five categories of reserves are significant, listed in order of response time:[i]

- Frequency Response Reserves (milliseconds to seconds): The fastest reserves are used to respond to such contingencies as the loss of a generator or transmission line. They are activated automatically on individual generators and at control centers, and are rarely explicitly dispatched by the operator.

Wind integration studies and experience have shown that the additional variability and uncertainty associated with higher penetrations of wind will increase operating reserve requirements.

- Regulating Reserves (seconds): These are used during normal operation to maintain the balance between supply and demand due to random changes in generation or load. They are dispatched by the operator in times that are faster than the clearing periods of energy markets.

- Ramping Reserve (minutes to hours): These reserves respond to ramp events that occur over periods of minutes to hours. They can ramp their outputs either up or down and are designed to cover challenging operational conditions, such as wind forecast errors.

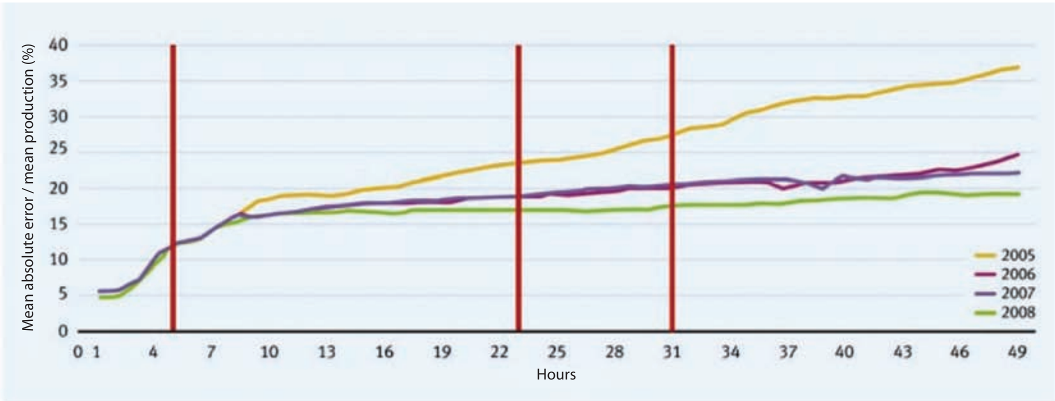
- Load-following Reserves (minutes): These are dispatched during normal operations by the operator to maintain the balance between supply and demand due to cyclical (e.g. daily, weekly) changes in demand or generation, on a slower timescale than regulating reserves.

- Supplemental Reserves (tens of minutes to hours): The slowest form of reserves, these resources are deployed during contingencies alongside faster reserves. They are designed to slowly ramp up and replace faster reserves, which are then available to address future contingency events.

Wind integration studies and experience have shown that the additional variability and uncertainty associated with higher penetrations of wind will increase operating reserve requirements.[10] The Federal Energy Regulatory Commission (FERC) has cited this increase as one of the most important sources of cost

[i] A variety of terms are commonly used to describe each type of reserve in different systems and different countries.[11]

Figure 3.3 The Evolution of Forecasting Errors versus Lead Time, 2005–2008



Note: The red bars mark the typical time when generation schedules become final and binding for different markets.

Source: Eurelectric, *Integrating Intermittent Renewables Sources into the EU Electricity System by 2020: Challenges and Solutions* (Brussels, Belgium, 2010).

increases from the integration of VERs in the U.S.[12] Understanding the full impact of this increase in operating reserves on costs will require a closer examination of how VERs affect each category of reserves.

Regulating Reserves. The uncertainty and the variability of VERs can create fluctuations in production on the order of minutes. Accommodating these fluctuations may require a modest increase in fast-responding regulating reserves required for normal operations.

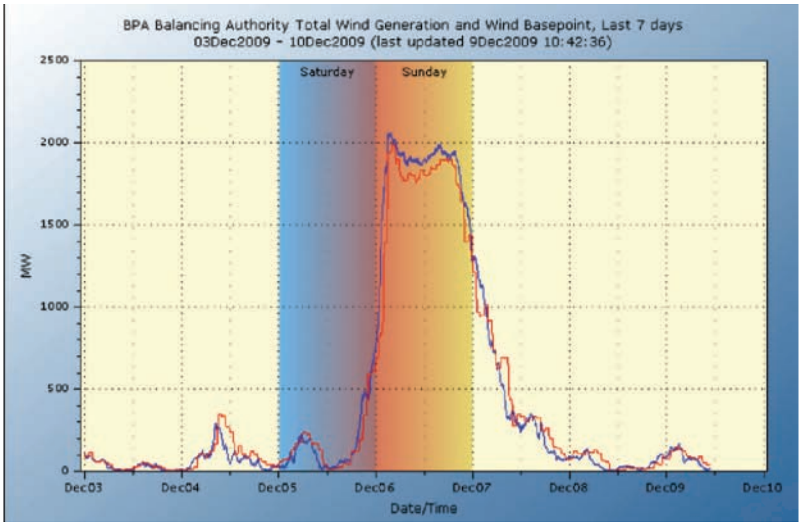
Frequency Response and **Supplemental Reserves.** All major international studies have concluded that large VER penetrations do not significantly increase the risks for traditional contingencies.[ii] Large penetrations are expected to be comprised of many small plants on the order of 1–5 megawatts (MW) over wide geographic areas, and it is highly unlikely that many of these plants simultaneously would stop producing.[13] Even when VERs do simultaneously ramp down, they typically take minutes to hours, which is much slower than traditional contingencies, such as a large generation plant tripping off-line, that occur in seconds.[iii]

Ramping and **Load-following Reserves.** Ramping and load-following reserves are primarily used to counteract VER forecast errors in the day-ahead scheduling of plants. At this timescale, wind forecasts have an average error of 15%–30% mean absolute error of production, despite the significant improvements in wind forecasting over the past decade, as illustrated in Figure 3.3.[14] For comparison, day-ahead load forecast errors are typically below 1% mean average error of production.[15] As a result, operators must conservatively operate the system assuming that the actual VER production could be at least 20% lower

[ii] These studies assume that requirements for fault tolerance are present in grid interconnection standards. This issue is described further in Section 3.4.

[iii] An exception is the occurrence of wind exceeding maximum allowable speed and causing multiple turbines to shut down simultaneously.

Figure 3.4 Ramp-up and Ramp-down Events in the Bonneville Power Administration Region



Note: The red line indicates the final scheduled wind generation (economic dispatch base point). The blue line indicates actual wind generation.

Source: North American Energy Reliability Corporation, *NERC IVGTF Task 2.4 Report: Operation Practices, Procedures, and Tools* (Princeton, NJ, 2011).

than forecasted, requiring large quantities of reserves, which are then dispatched throughout the day if forecast errors become apparent.

Load-following and ramping reserves also are used to hedge the risk of VER ramp events. Though not a traditional contingency, ramp events can present a significant operating concern. The risk of ramp events in most cases comes from the uncertainty of when they will occur and how long they will last. Indeed, predictions of ramp event occurrence and timing are often difficult and can result in large and sudden forecast errors that deplete reserves that are on-line in a time too short to activate reserves that are fully off-line.[16]

Figure 3.4 shows two ramp events that depleted reserves procured by the Bonneville Power Administration in December 2009. Wind output ramped up sharply in the late hours of December 6 and the early morning of December 7 to nearly 2,000 MW—a substantial portion of the agency's total wind generation capacity (around 3,000 MW at the time). BPA deployed more than 90 percent of its reserves as the wind ramped up and BPA had to curtail some wind generation by issuing generation limits to wind generators, in order to avoid violating its reserve requirements. Wind output then ramped down to zero through the night hours of December 7 and the morning hours of December 8. This down ramp resulted in BPA depleting 100 percent of its reserves and prompted BPA to curtail transmission schedules for wind generators. Uncertainty in both the size and duration of ramp events complicates operator responses.

In the remainder of this section, we discuss a set of tools that can serve to reduce the cost of reserves associated with VERs. Many of these tools will allow the electricity market to better address the impending need for flexible resources: if the electricity commodity market is liquid and a strong price signal exists, the fastest flexible resources will be able to offer their services closer to the time when they are actually needed. This allows the system to avoid locking in resources that it will not eventually need, and these can be freed for other uses.[17]

Improve Variable Energy Resource Forecasts and Situational Awareness

Improving the accuracy of VER power production forecasts is one of the most straightforward ways to reduce the impact of VERs on reserve requirements and thus system operating costs. Reducing day-ahead forecast errors lessens the risk of under committing generation, thus also diminishing the ramping reserves needed to hedge this risk. Reducing real-time forecast errors can increase the accuracy of the real-time dispatch schedule, diminishing the imbalances that must be corrected by regulating and load-following reserves.

Wind power generation forecasts used in power system operations typically are based on a combination of data from large-scale numerical weather prediction (NWP) models maintained by public meteorological agencies and meteorological and power production data measured at individual VER installations. NWP datasets are wide in regional scope and comprehensively describe many aspects related to the state of the atmosphere at a given time. However, due to the computational complexity of the models used to generate these datasets, they are typically refreshed slowly and have relatively poor spatial resolution. Improvements in the affordability and power of computational technologies have yielded significant advances in NWP models in recent years. In the U.S., the National Oceanic and Atmospheric Administration (NOAA) recently began updating NWP data every hour instead of every six hours, and the agency is developing further improvements.[18]

Local meteorological and power production measurements at individual VER installations are also an important input to VER forecasting models. These datasets are typically refreshed more often than the NWP data that NOAA provides and have higher spatial resolution. Individual VER owners and forecast vendors collect and use the data to produce power production forecasts. VER generators in some regions where independent system operators (ISOs) and regional transmission organizations (RTOs) exist are required to provide data to system operators for the purpose of forecasting. However, this is not universally the case.[19] System operators have indicated that accurate data from VERs are critical to generating accurate forecasts.[20] In a November 2010 Notice of Proposed Rulemaking, FERC proposed to mandate reporting of such data for the purpose of centralized forecasting in real time or near-real time by system operators in regions with significant penetrations of VERs.[21] Increased data sharing would improve power production forecasting, and is widely understood to be an important step in reducing the cost of VER integration. At the same time, increased data reporting and compliance monitoring will also result in increased costs, and these increases may exceed the benefits in regions that do not expect substantial penetrations of VERs. As of November 2011, a final rule had not been issued.

Local data from VERs are considered proprietary and confidential, and they are rarely shared beyond forecast vendors and system operators.[22] NOAA has cited limited access to wind data at wind turbine–hub height as a significant limitation to the prediction accuracy of current NWP models and has urged FERC to consider also mandating VERs to share local meteorological measurements with NOAA.[23] Of course, protections would need to be in place for commercially sensitive information.

Such confidentiality arrangements already exist between NOAA and many airline companies. NOAA also has been working to form voluntary data-sharing partnerships with industry stakeholders and has embarked on efforts to better quantify the potential benefits that increased data access may yield.[24]

FINDING

Greater sharing of meteorological data would improve wind forecast accuracy in regions with high penetrations of VERs.

Beyond improving power production forecasts, developing and improving tools for ramp-event prediction also can reduce the impact of VERs on system operating costs. Unlike a conventional VER forecasting system, a forecasting system for ramp events has the goal of identifying specific meteorological conditions that could translate to high risks for ramp events. System operators can take specific preventative actions to protect system reliability and timelier, less resource-intensive decisions to address potential ramp events when forecasting tools observe these conditions.[25] A recent review of ramp event-forecasting methodologies by Argonne National Laboratory indicates that ramp-event prediction remains a relatively novel problem for meteorologists and reports that existing forecasts tend to be "unreliable and of low accuracy."[26] Fortunately, ramp-forecast skill is rapidly increasing, driven both by public research institutes as well as private wind-forecasting companies. Like the case for improving regular VER forecasts, it has been suggested that providing forecasters with greater access to meteorological data would improve forecasts.[27]

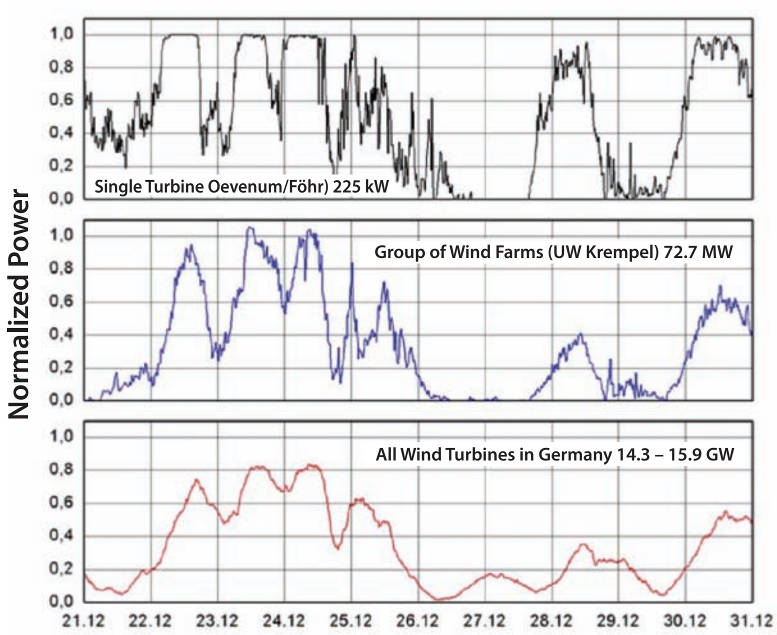
Reducing the potential impacts of VER ramp events also will require deploying technology to increase operators' situational awareness of system conditions. Some of these tools, such as phasor measurement units, are described in Chapter 2. Finally, data analysis and visualization tools that effectively aid operators' decision-making will be important. Many system operators in the U.S. with growing penetrations of VERs are in the process of developing programs to aid in identifying and responding to the risks of VER ramp events.[28]

Make More Frequent Decisions Closer to Real Time

As discussed earlier and illustrated in Figure 3.3, the accuracy of wind forecasts increases appreciably closer to real time. There are two primary mechanisms for improving scheduling practices to take advantage of this phenomenon: shorter gate-closure periods (the time before the operating period when generation schedules become final and binding) and shorter commitment periods (the length of time the generator is committed to produce). Historically, both measures have been deployed in various regions to counter the variability and uncertainty of loads. Recent research and operating experiences from around the world have shown that they also can yield potentially large benefits in accommodating large penetrations of VERs.[29]

Moving gate closure nearer to the corresponding operating period results in more accurate forecasts, as shown in Figure 3.3, and better-performing schedules in systems with a significant penetration of VERs. Various mechanisms already exist to achieve shorter gate-closure periods due to the large benefits that are available even in systems without VERs. Notably in the U.S., most ISO/RTO regions operate real-time markets that layer on top of day-ahead markets. A generator with an obligation from the day-ahead market may still buy or sell in shorter-term markets that are closer to real time. Intraday markets have been developed on top of power exchange markets, initially in Spain and then in other countries, and their use has been mandated recently within the European Union. While these markets differ by name and implementation, in practice they all shorten the gate-closure period.

Figure 3.5 Individual and Aggregated Power Outputs of Wind Turbines



Source: Copyright © Fraunhofer IWES, Germany; Institute for Solar Energy Technology, Wind Energy Report Germany 2005 (Kassel, Germany, 2005); H. Holtinnen et al., Design and Operation of Power Systems with Large Amounts of Wind Power: Final Report, Phase One 2006–2008, research note 2493 (Espoo, Finland: VTT, 2009).

Shorter operating periods allow schedules to roll over more smoothly and forecasters to refresh their forecasts more often, which reduces the magnitude of forecast errors and associated scheduling errors. With increasing penetrations of VERs, shorter operating periods also could align market operations more closely with the predominant variations associated with wind, which most often vary over tens of minutes.[30]

In the U.S., most RTO/ISO regions already administer wholesale energy markets with short gate-closure periods and five- to fifteen-minute scheduling and dispatch. For the Southeast and the portions of the Western Interconnection outside the California ISO, however, the electric grid is managed by transmission owners that rely mostly, if not entirely, on bilateral transactions between market participants. Generators selling into these systems usually are required to submit fixed hourly schedules that are set in advance.[31] This arrangement can result in discrimination between vertically integrated utilities who own the transmission network and independent generators who own VERs.[32] Implementing shorter gate-closure periods or shorter scheduling periods in these regions would help mitigate such a concern and reduce the overall cost of maintaining real-time balance between generation and load in systems with high penetrations of VERs. With these points in mind, in a November 2010 Notice of Proposed Rulemaking, FERC proposed to reduce scheduling intervals nationally from 1 hour to 15 minutes.[33] As of October 2011, a final rule has not been issued.

Cooperate among Balancing Areas

Enlarging the regional scope of power system operations through cooperation or integration among balancing areas can offer reliability

By aggregating a geographically diverse collection of VERs, rapid changes in the outputs of individual VERs are replaced by the slower output variations of the aggregated resource.

and economic benefits when integrating large amounts of VERs.[34] By aggregating a geographically diverse collection of VERs, rapid changes in the outputs of individual VERs are replaced by the slower output variations of the aggregated resource.[35] The cause is the geographical diversity in the weather that is seen by geographically dispersed turbines and plants. Figure 3.5 illustrates the impact on variability of spatial dispersion of wind resources, a trend that is similar for solar generation.[36]

The economic benefits of cooperation between regions could be significant: the Western Wind and Solar Integration Study identified cost savings across the WestConnect region of $2 billion from a total annual operating cost of $43 billion if the area operated as five large regions rather than many small zones, assuming that adequate transmission exists.[37]

By the same principle, the forecasted aggregate output of turbines over a wide geographic area is more accurate than the forecasts for single turbines. One study found the day-ahead forecast error could be reduced by as much as a factor of two when the geographic region diameter was increased from 140 kilometers to 730 kilometers.[38] Capturing the benefit of wide-area aggregation requires that sufficient transmission be available, which, given the remoteness of many wind- and solar-rich locations, is unlikely without new construction. This issue and recommendations for addressing it are discussed in Chapter 4.

The benefits of geographical smoothing historically have been observed with the aggregation of loads over wide regions. The resulting decrease in variability, balancing responsibilities, and associated increase in market liquidities made cooperation among balancing areas economically worthwhile in many parts of the U.S., decades before VERs became widespread. Utilities in Arkansas, Louisiana, Mississippi, Oklahoma, Nebraska, Kansas, Texas, and New Mexico cooperate via the Southwest Power Pool. Regions like the Midwest, New York, and New England ISOs and the PJM interconnection all grew out of the consolidation of independent balancing areas within their respective regions.

However, cooperation among balancing areas for the explicit purpose of VER integration remains a relatively new activity. A variety of possible cooperation schemes have been proposed, including the interregional communication of regional imbalances, the creation of wide-area balancing markets, the provision of operating reserves from other jurisdictions, the transfer of load responsibilities from one jurisdiction to another, and interhourly or dynamic scheduling between balancing areas. The North American Electric Reliability Corporation (NERC) has recognized the need to review and study interregional cooperation, and industry-led efforts exist.[39] For example, WestConnect created the Virtual Control Area Work Group to investigate methods and technology available for participating balancing areas to function as a single "virtual" control area for specific operations, and the Bonneville Power Administration has several pilot programs in place.[40] Ultimately, the transmission capacity that exists between neighboring balancing areas will determine the degree to which cooperation or consolidation is possible. Limited transmission between balancing areas may slow their aggregation. However, this issue has not been studied in depth in the U.S.

FINDING

Improving forecasts, reducing gate-closure and operating periods, and expanding cooperation among neighboring balancing areas are operational changes that can offer reliability and economic benefits when integrating growing variable energy resource penetrations. System operators and utilities in many regions in the U.S. are making progress toward implementing these changes.

3.3 ENSURING ADEQUATE SYSTEM FLEXIBILITY

The operation of a system with a substantial presence of VERs will be different from today's operation. The future well-adapted mix of generation technologies also will change, probably reducing the proportion of less flexible baseload units and increasing the percentage of more flexible resources, always depending on the level of VER penetration. These flexible resources must be capable of continuously modifying their output, or "cycling," to accommodate the variation in the output of the VERs.

Flexibility is not a new concept in power systems; however, its importance has been greatly amplified in recent years by the prospect of large penetrations of wind generation.[41] Power system flexibility has both technical and economic components. Technically, the rate at which a generator can change its output, known as its ramp rate, is limited by its design and technology. Some units, such as nuclear and large coal-fired generators, have slow ramp rates; substantial changes in output can take hours to tens of hours. Other units, such as gas turbines, can effect changes in their output within fractions of an hour, while hydro units can ramp in fractions of a minute. But requiring resources to cycle frequently has negative economic consequences. Large base-load units and midrange plants that were not designed for frequent cycling will incur increased maintenance costs, reduced life, or both; their varying output moves generators away from their point of maximum efficiency; and the financial compensation paid to generators for their start-up costs may become significant. These plants, characterized by relatively high capital costs but low variable costs, need to operate with high capacity factors in order to remain economically viable, further increasing the financial incentives they would need to cycle regularly.

The increased demand for flexibility from VERs will not necessarily translate into a need for new capital investments. In Europe, several regions already experiencing high penetrations of wind power have had enough flexibility in their existing generation fleets to successfully integrate significant levels of wind without substantial new dispatchable generation investment.[42] In preliminary studies of VER integration in North America, some regions have concluded that they, too, already have sufficient flexible capacity to accommodate the anticipated growth in VERs over the next decade or two.[43]

FINDING

The existing generation fleets in some regions appear to have sufficient flexibility to accommodate levels of variable energy resource penetration anticipated during the next decade, although this is not universally the case.

As expected VER penetrations continue to increase, however, regions with organized wholesale markets may have insufficient investment in flexible plants due to the uncertainty regarding the most appropriate technology mix, the rate of renewables growth, and the economics of such a mix under anticipated future prices and operating conditions. Several European countries with significant or anticipated penetrations of wind generation are currently addressing this issue.[44] There is no consensus yet on the most appropriate solutions, which could include enhanced capacity mechanisms, new categories of remunerated ancillary services, or other regulatory instruments. If necessary, appropriate regulatory measures or changes to market design should be developed to facilitate adequate levels of investment in flexible generation plants to ensure system reliability and efficiency.

Another important issue is offering sufficient incentives to ensure that flexible resources will offer their flexibility to the power system. A recent study by the International Energy Agency found that more than the incentive provided by fluctuating electricity prices will be needed to prompt owners of flexible resources, particularly of slower, intermediate, or baseload plants, to offer the full extent of their flexibility to the markets. The agency plans to address this topic in the next stage of its Grid Integration of Variable Renewables project.[45]

FINDING

Generators require strong and clear economic incentives to make investments in flexibility and operate flexibly within the system. Research is needed to design market rules and incentive mechanisms for this purpose.

In this section, we describe several existing and upcoming resources capable of offering flexibility to systems with high VER penetrations. In practice, their usefulness may be limited if transmission constraints exist. With key transmission lines congested, the most economic flexible resources can become inaccessible, requiring the dispatch of more expensive resources.

Thermal Generation

Thermal generators—mainly coal, gas, and nuclear—account for around 90% of the capacity of the U.S. generation fleet.[46] They supply the bulk of the flexibility within the power system today by participating in energy markets and offering dispatchable capacities, such as operating reserves. Peaking plants, including diesel and gas combustion turbines, can be quickly started and ramped. However, they can be costly to operate because of higher fuel costs and lower efficiencies. Intermediate plants, including combined-cycle gas turbines, improve on the efficiency of peaking plants, losing some flexibility in the process. Baseload plants, including nuclear, coal, and some combined-cycle gas generation, are not usually operated flexibly. While they have the lowest per-kWh operating cost, they generally have relatively narrow power output ranges and slow ramp rates, and they incur significant real and opportunity costs when made to ramp and cycle.[iv] The optimal mix of the three categories of generation should consist of a portfolio with an adequate balance of flexibility and production costs.

While some technological limits exist in the flexibility available from thermal generation, experience has shown that the factors constraining their flexibility are mostly economic. Making a thermal generator flexible and accessing this flexibility incurs costs. Designing a flexible thermal plant and operating it flexibly require

[iv] It is technically possible to operate nuclear generation facilities flexibly. Achieving flexible operations requires relatively minor technical modifications to plant designs and fuel content. Électricité de France regularly cycles their reactors to provide a range of grid services, including primary frequency regulation and daily load following. Some of their units experience up to 250 power variations between 10% and 80% of their nominal rated capacity per year.[47]

Constrained by the need to comply with emissions regulations, some thermal generators may require additional emissions-reduction investments before their flexibility can be accessed.

a number of redesigns and operating practices that all decrease the efficiency of the system. Furthermore, continuously cycling thermal generators will increase maintenance costs and decrease equipment reliability and life. By reducing efficiency, cycling fossil fuel–based generation also may increase emissions of carbon dioxide, nitrogen oxides, sulfur oxides, or particulates, especially in the case of coal generation.[48] Constrained by the need to comply with emissions regulations, some thermal generators may require additional emissions-reduction investments before their flexibility can be accessed.

Hydro Generation

The success of wind in Denmark and its integration in the Nordic countries is generally attributed to the availability of good interconnections and large quantities of hydro generation in this region, particularly in Norway.[49] Hydro generation has two characteristics that make it a highly flexible resource.[v] First, these facilities are able to rapidly ramp their output over a wide range while maintaining high efficiency. Second, they can store potential energy for later generation by varying the water levels of their reservoirs.

VERs can offset hydro production when their production levels are high and allow water to accumulate in hydro reservoirs. The water collected then can be used to generate power when VER production levels are low and marginal production costs are high enough. Hydro is also an economical form of generation because it can operate with essentially zero fuel cost, although water used for generation today will not be available if needed in the future, incurring an opportunity cost.

In practice, the operation of hydro generation is usually subject to limits in place to minimize flooding and other adverse impacts, for example on fish migrations, water quality, aquatic ecology, tourism, and nearby residents and businesses. These limits can restrict their flexibility, particularly during times of abnormally high or low water. The high water flows along the Columbia River during the summer of 2010 limited the flexibility of the Bonneville Power Administration's hydro generation, as the plants were forced to operate in order to minimize water spilling over the dams and keep total nitrogen saturation at levels safe for fish. This loss of flexibility coincided with a period of high wind, forcing wind generation to be involuntarily curtailed.[50]

Concerns over flooding and environmental impacts limit not just operation but the construction of hydropower facilities.[51] As a result, hydro generation in the U.S. makes up only about 8% of total capacity and supplies around 7% of total energy, even though it is highly viable as a generation technology.[52] However, some potential for capacity expansion has been identified from small hydro and the conversion of non-powered dams to powered ones.[53] It is unclear how much grid flexibility would be obtainable from these plants, as many of them may end up being built with limited water storage capacity. The future role of hydro generation for the purpose of providing system flexibility is likely to be valuable but limited.

[v] In this report, "hydro generation" refers to impoundment, or dam-based, hydropower unless otherwise noted. This is in contrast to run-of-river hydropower installations with little or no water storage. By avoiding the high dams and extensive land inundation that characterize impoundment hydropower, pure run-of-river installations are typically smaller and have less impact on the environment. However, these facilities produce variable outputs and are often categorized as a type of VER.[54]

Additional Sources of Flexibility

Faced with the economic trade-offs surrounding flexible thermal generation and the scarcity of resources for hydro generation, demand response and energy storage could play important roles as new sources of flexibility in the future. Because demand response works by offsetting physical generation, it has the potential to offer flexibility at lower marginal costs and emissions than thermal generation.

Demand response, discussed in detail in Chapter 7, occurs when customers modify their electricity use in response to signals from the system operator or changes in the price of electricity. In the context of VER integration, demand response that is sufficiently nimble and reliable has the potential to offset operation and capital investments of more expensive flexible generation. Where VER output is not well correlated with load patterns, as often is true of on-shore wind, time-varying prices may induce load shifting that makes better use of off-peak VER generation.

The earliest and most widely adopted application of demand response in the context of flexibility is in response to reliability threats. Emergency and interruptible load programs provide customers with incentive payments or rate discounts in exchange for load reductions during declared system emergencies. When unusually high demand or loss of a major generator or transmission link threatens a power system's operating reserve margin, demand response may be used to maintain stability by calling on customers to shed load or manually disconnecting specific customers from the grid. This technique already has been extended to protect system reliability during VER ramp events, including a February 26, 2008, event in the Electric Reliability Council of Texas (ERCOT).[55] As discussed in the Western Wind and Solar Integration Study, this application of demand response reduces costs by avoiding the need to hold additional reserve generation online for all 8,760 hours of the year to deal with relatively rare ramp events.[56] In some regions with wholesale markets—most notably ERCOT—demand response represents a small but growing share of operating reserve and regulation service markets, providing real-time flexibility on a more routine basis.

In the context of VER integration, demand response that is sufficiently nimble and reliable has the potential to offset operation and capital investments of more expensive flexible generation.

A challenge of expanding traditional load-control demand response programs to accommodate VERs is the concern that more frequent activation may lead to fatigue and an eventual lack of willingness of load to participate. This has not been targeted in demand response pilots, and merits further study. Use of demand response for higher-frequency adjustments also requires a better understanding of the speed and predictability of the response of load to control signals and the behavior of end users in an environment of rapid and perhaps frequent curtailment or load adjustment. Dynamic pricing programs that provide customers with greater transparency and control may offer attractive alternatives to load control programs, particularly if combined with automated control technology. As discussed in Chapter 7, dynamic pricing is in its infancy in U.S. electricity markets, although successful long-term programs, such as Georgia Power's real-time pricing tariff for large industrial and commercial customers, suggest its efficacy.

Energy storage using pumped water, compressed air, batteries, flywheels, and other storage technologies could also supply flexibility.[57] Pumped hydro energy storage (PHES), where the generator and water turbine can operate as a motor and pump, is of particular value as a flexible resource. During periods of excess energy from VERs, water can be pumped into the elevated reservoir and used to generate at a time when rapid up-ramping is required, providing time for slower units to respond. The U.S. currently has approximately 22,000 MW of PHES capacity.[58]

PHES facilities do face important limitations. They are only viable in locations that have sufficient water availability and are capable of siting large reservoirs at different heights. Many of the best locations for PHES facilities in the U.S. have already been developed. Environmental concerns regarding the construction of large dams and reservoirs further restrict the viability of additional PHES installations. Only one PHES facility with capacity of more than 100 MW has been constructed in the past 15 years.[59] FERC has recently issued preliminary permits to more than 40 projects that total over 32,000 MW of additional PHES capacity.[60] However, a preliminary permit does not authorize construction, and it is unclear how many of these projects will eventually be constructed.

Compressed air energy storage (CAES) is the only other storage technology that has achieved long-term utility-scale operation. CAES facilities use electricity to compress air and inject it into underground caverns for storage. When the energy is needed, the compressed air is heated and run through a turbine to generate electricity. Only two utility-scale CAES facilities have been constructed worldwide: a 290 MW facility with two hours of storage in Huntorf, Germany, that entered commercial operations in 1978 and a 110 MW facility with 26 hours of storage in McIntosh, Alabama, that entered commercial operations in 1991. Supported in part by funds from the American Recovery and Reinvestment Act of 2009, New York State Electric & Gas and Pacific Gas & Electric have recently announced plans to construct new CAES facilities with respective storage capacities of 150 MW/16 hours and 300 MW/10 hours.[61] These efforts promise to advance the maturity of CAES technology and reduce the uncertainty regarding its cost at commercial scale.

To date, utility-scale battery and flywheel technologies have achieved limited energy capacity and have only been deployed in a small number of pilot projects.[62] These technologies remain too costly for most applications today, at a price about two to five times higher than competing sources of flexibility.[63] Storage technologies are currently the focus of research, and costs could fall in the coming decades. If they do, the use of bulk energy storage in the power system could expand dramatically.

Obviously, curtailment of VER generation is another source of flexibility. VER output can be reduced by temporarily disconnecting individual generators. Some advanced wind turbine designs also allow controlled feathering of their blades to partially reduce their output. While VERs do not appear to provide operating reserves anywhere in the U.S. today, studies have shown they are technically capable of doing so.[64]

In some cases, curtailing VER outputs can be the economically optimal decision—for example, during "minimum generation events" when the combined generation of wind and baseload facilities exceeds the load. If the baseload plants are already operating at their technical minimums, either they must be shut down or the wind plants must be curtailed. This latter option is often more economically efficient in the short run because it avoids the large costs associated with shutting down the baseload plants and then starting them up a short time later. In the long run, the prospect of baseload units being shut down during minimum generation events would provide added incentive for investments in plants that can operate more flexibly at lower cost. Significant penetration of VERs in general will cause baseload generation facilities to cycle more frequently, potentially leading to loss of efficiency of these plants and potential emissions increases, though this issue is not yet well understood.[65] VER "must-take" operating practices, as they are currently established in the EU, will amplify this effect.

FINDING

Care must be taken in the design of operating procedures to ensure that the option to curtail the output of VERs is always available to operators and that it is selected when it is economically efficient to do so.

3.4 INTERCONNECTING VARIABLE ENERGY RESOURCES

Beyond the variability and uncertainty of their outputs, VERs exhibit other characteristics that are very different from conventional generators. Wind turbine generators do not operate at constant speed, which in most cases results in an ac output with variable frequency and voltage that is not directly compatible with the grid. Solar PV systems produce a dc voltage, which also cannot be directly connected to the grid. Both require an interface system based on power electronics that converts their outputs to grid compatible form.

The physical characteristics of VER generation and its specific connection to the grid result in a different contribution to the inertia of the power system than that of conventional plants. All conventional forms of generation produce electricity by rotating a large metal mass within a magnetic field. Conventional generators also include a rotating turbine with large mass. The considerable stored kinetic energy of this aggregate mass gives these machines the transient ability briefly to provide electrical output power in excess of or below their mechanical input power to accommodate a sudden change in load—in effect, to act like a shock absorber for the system. Power systems rely on this inertial response for maintaining system stability. During such a transient, the mechanical input to the generator is changed to return the generator speed to its proper value.

Most wind turbines and all solar PV plants lack significant inertial response. While wind turbines do store mechanical energy as rotating inertia, there is a significant distinction between them and conventional generators. While the mechanical input power to conventional generators can be increased to return the generator to its correct speed, this cannot be done for wind turbines as the mechanical input power is the wind, and this cannot be increased except in the rare case where the wind turbine output has been curtailed.[vi] When wind and PV account for larger portions of the generation fleet, the inertial response of the overall system will decrease, potentially increasing the risk of power system stability problems. Reduced system inertia due to the displacement of conventional generation with wind already has been observed in the Irish and the Hawaiian systems, and researchers have raised a similar concern for the Western Interconnection.[66] It has been shown that wind generators can provide some degree of inertial response through appropriate design and control of their power electronic interface, and solar PV generators can emulate an inertial response if provided with energy storage.[67] However, as shown by experience, current wind turbines have an inertial response performance below that of conventional generators.[68]

When wind and PV account for larger portions of the generation fleet, the inertial response of the overall system will decrease, potentially increasing the risk of power system stability problems.

Other characteristics of VERs also need consideration. Because of their power electronics–based interface to the grid, VERs can inject harmonic voltages or currents into the grid. This may result in a distortion of the sinusoidal voltage waveform experienced by other pieces of equipment connected to the system, potentially disrupting their operation. The varying

[vi] Some modern wind turbines can employ blade-pitch control to affect some control of input.

power output and complex control systems of VERs could cause voltage to oscillate rapidly, or flicker. Finally, because their response to faults is different from that of conventional generators, VERs often require customized protection equipment.[69]

Most of these challenges can be readily addressed by enforcing a set of interconnection standards. The interconnection standard provisions for conventional generators are designed to ensure that generators do not harm the grid and that they will contribute to the stability and reliability of the grid when required. Due to their very low penetrations, so far VERs in the U.S. have been required to meet few standards. As a result, their expected impact on the system has not yet been properly formalized, and they generally have not played an active role in maintaining system stability and reliability.

FINDING

Before the penetrations of VERs in the U.S. increase to those levels foreseeable with renewable portfolio standards, interconnection standards must be revised to include VERs within the power system and allow them to perform functions that can enhance grid behavior. These functions must be compatible with their unique physical and electrical characteristics.

The nation has made some progress over the past decade on the development of interconnection standards. FERC issued Order No. 661-A in December 2005, specifying that wind generators meet three performance requirements before interconnection rights are granted.[70] The first requires that wind generators not disconnect from the system in response to a transient system voltage reduction, a capability known as "low-voltage ride-through." Power systems employ sophisticated protective relaying and control schemes throughout the transmission system to clear faults quickly when they occur. When faults do occur, the system voltage often drops until the fault is cleared. It is important for generators to remain connected during this time as a substantial loss of generation could further reduce voltage and threaten the stability of the system. The order also requires VERs to provide reactive power support, which allows them to contribute to voltage stability, and it requires wind generators to be compliant with the existing supervisory control and data acquisition systems that utilities and system operators use to remotely control and monitor the power system.

FERC has yet to issue a similar order for solar-based generation technologies. If the penetration of solar generators increases to a significant level, performance standards will become important. Solar PV generators in particular share many technical characteristics with wind generators, so it may be appropriate to extend the provisions of Order No. 661-A to them, as the Interconnection Standards Review Initiative of the California ISO recently proposed.[71] Doing so will require the resolution of inconsistencies between Order No. 661-A and existing standards for solar generation interconnection. For example, Order No. 661-A requires wind generation to have low-voltage ride-through capability, while the primary technical standard governing the interconnection of distributed solar generation requires distributed generation to disconnect immediately upon sensing low-voltage conditions.[vii] NERC currently has two task forces designed to reconcile these standards and develop others for distributed solar generation.[72]

[vii] This provision is in the Institute of Electrical and Electronics Engineers Standard 1547.

Recent technical developments have enabled engineers to construct wind generators that are compatible with most of the stability and reliability performance requirements typically imposed upon conventional generation.[73] Manufacturers typically construct modern VER plants with advanced power electronics and controls. Among other capabilities, these power electronics give plants reactive power control. Advances in mechanical engineering also have allowed modern wind turbines to curtail their power outputs with precision and in real time through rotor pitch control. This capability, known as active power control, allows the turbines to maintain a fixed power output below maximum or a maximum up-ramp rate.

NERC, ISOs, RTOs, and utilities are closely monitoring the impact of VERs on grid reliability to determine whether existing requirements should be modified or additional requirements are needed. Following recommendations from its 2009 report on integrating VERs, NERC has created a subgroup within its Integration of Variable Generation Task Force to review the adequacy and consistency of U.S. interconnection standards for all generation, both VERs and conventional.[74] The task force is expected to release a report by the end of 2011 making recommendations on interconnection issues.

FINDING

Interconnection requirements for all generation technologies, both variable energy resource and conventional, must be designed for anticipated rather than existing conditions. The technology necessary to comply with anticipated standards is available.

3.5 CONCLUSIONS AND RECOMMENDATIONS

Motivated by state and federal policies, the proportion of generation from VERs in the U.S. could grow substantially over the next several decades. While variability and uncertainty are familiar concepts in power systems, wind and solar generation, as new sources of both, could complicate power system operations and planning.

High penetrations of wind and solar generation will require operators to procure additional operating reserves. Increased operating reserve requirements are viewed as one of the primary sources of potential system operations cost increases associated with the growth of VERs.

Improving the accuracy of VER power production forecasts and VER ramp event forecasts could reduce the magnitude of these cost increases. Improving both types of forecasts relies critically on forecasting methodological improvements and the increased availability of granular meteorological data, especially data measured at individual VERs.

RECOMMENDATION

Industry and government should work to expand the sharing of granular meteorological data measured at VER sites for the purpose of improving wind power production forecasts.

Changes to system operating practices could also facilitate the cost-effective integration of high penetrations of VERs. Integrating forecasts fully into power system operations could yield significant benefits and remains an important challenge, but one industry appears to be tackling well. Moving the deadline when generation schedules become final and binding closer to real time and reducing the duration of generation commitment periods would allow system operators to take advantage of the fact that wind forecast accuracy improves appreciably closer to real time. These changes promise to reduce the overall cost of maintaining real-time balance between generation and load in systems with high penetrations of VERs.

Merging or expanding cooperation between neighboring balancing areas, as well as reinforcing when needed the interconnection capacity among them, also would reduce the impact of growing VER penetrations on operating reserves.

RECOMMENDATION

Fully integrating wind forecasts into system operations, moving scheduling decisions closer to real time, and expanding cooperation among neighboring balancing areas are all operational changes that should be considered in regions that expect high VER penetrations. These changes can reduce the negative impact of high VER penetrations on system operating reserve requirements.

High penetrations of VERs will amplify the importance of power system flexibility. Flexible resources will be needed to accommodate the variation in the output of VERs. Many regions already have sufficient flexibility in their existing generation fleets to accommodate the VER penetrations anticipated in the immediate future. However, additional flexibility may be needed in other regions and further into the future. This flexibility can be provided by thermal or hydro generation, demand response, and energy storage. But it is likely to prove difficult to expand hydro capacity. There are concerns regarding the ability of present wholesale market designs to attract the necessary volume of flexible resources.

RECOMMENDATION

As VER penetrations increase, mechanisms that provide incentives for investment in flexible generation and for operating flexibly should be devised and deployed. The design of these mechanisms is an important area for research today.

Finally, beyond the variability and uncertainty of their outputs, VERs also exhibit other physical and electrical characteristics that are very different from conventional generators. As anticipated VER penetrations increase, it will become increasingly important to design VER grid interconnection standards that allow VERs to enhance grid functionality while remaining compatible with their unique characteristics. The U.S. has made considerable progress in this area in recent years, and a variety of organizations are continuing to closely monitoring the adequacy of existing interconnection requirements.

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Chapter 4: Transmission Expansion

In this chapter, we consider regulatory policy affecting transmission expansion, with particular focus on the implications for transmission of the integration of large-scale renewable generation. Public policies aiming to access the best onshore wind and solar resources will require new transmission lines crossing state boundaries, independent system operator boundaries, and land managed by federal agencies. This chapter focuses on the transmission planning, business models, cost allocation, and siting challenges related to this expansion.

Section 4.1 provides background on the drivers and business models for transmission development in the U.S. A discussion of transmission planning follows. In Section 4.2, we highlight the importance of interregional and interconnection level transmission planning. We also find that existing data and planning methods are inadequate to meet the challenge of renewables integration and highlight transmission planning under uncertainty for complex networks as an important area for research.

Section 4.3 discusses transmission cost allocation, starting with a review of current practices in the U.S. We find that cost allocation should be intimately linked to transmission planning. We identify a set of core principles that should be followed as closely as possible to ensure that cost allocation is not a barrier to efficient and reliable network expansion.

Section 4.4 introduces challenges related to siting new transmission capacity. We find that current siting procedures are biased against approving interstate transmission projects and are a significant hurdle to efficient transmission expansion.

Section 4.5 provides our conclusions and recommendations. We first recommend the creation of permanent processes for conducting planning of interregional transmission projects at the interconnection level. We also recommend the compilation of detailed and comprehensive data on the U.S. bulk power system in order to support research on the methods that will be needed for effective interconnection level planning. We recommend the use of the cost allocation principles introduced in Section 4.3 as well as the adoption of a hierarchical approach to cost allocation that includes a single, uniform procedure for the allocation of costs between regions within each interconnection but allows individual regions to adopt their own internal cost-allocation procedures. Finally, we recommend that Congress grant the Federal Energy Regulatory Commission enhanced siting authority for interstate electricity transmission projects.

Several factors beyond normal growth in electricity demand will require new investment in transmission capacity in the next two decades. Perhaps the most important is the need to integrate large-scale renewable generation. The U.S. federal government and all state governments provide financial support for the use of renewable energy to generate electricity, and 29 states and the District of Columbia have enacted quantitative requirements.[1] These programs will spur growth in large-scale renewable generation, such as large wind farms, that will be connected to the high-voltage transmission system.

Also driving expansion, the recession-induced fall in electricity demand and the shale gas revolution have lowered electricity prices and adversely affected the economics of operating many older coal-fired units. A suite of new rules from the U.S. Environmental Protection Agency may provide further incentives for early retirement of those units. A number of recent studies have concluded that, as a result, significant early retirements are likely in the coming decade.[2] Early retirements and changes in dispatch will change the geographic pattern of generation and require new investment in transmission facilities.

In the reference case of its 2011 Annual Energy Outlook, for instance, the Energy Information Administration projects that 46% of the increase in total generating capacity in the electric power sector between 2010 and 2030 will be powered by non-hydro renewables, which accounted for only about 4.5% of 2010 capacity. Almost 90% of this increase is projected to come from growth in wind and solar capacity.[3]

Wind and solar generators have two characteristics that challenge transmission systems. First, even when fully functional, their available output can vary from zero to full capacity in relatively short times and is less predictable than output from other generation technologies. We discussed the implications in Chapter 3. The second characteristic, as noted in Chapter 1, is that many of the best onshore wind and solar resources are located far from major load centers and are, therefore, far from the existing transmission system. If they are to be tapped efficiently, an increasing fraction of transmission lines will cross state borders, independent system operator (ISO) regions, and land managed by federal agencies such as the U.S. Forest Service. While some boundary-crossing lines have been built in the past, that experience underscores a number of obstacles such projects face.[4] As we discuss in Section 4.2, there is too little useful transmission planning at regional, interregional, or interconnection-wide levels; the costs of boundary-crossing projects can be allocated only through project-specific negotiations; and the need to obtain construction permits from multiple authorities makes it difficult to site and build boundary-crossing lines.

Some have argued that the best solution to this suite of problems is to construct a nationwide overlay or "super-highway" grid.[5] Others favor large, discrete transmission projects that connect sizeable renewable resources to major load centers.[6] Still others defend a more conventional buildup of transmission reinforcements—within regions and across multiple regional boundaries—and more use of local renewable resources.[7] We do not recommend or oppose any particular suite of investments. Given the complexity of transmission expansion and the many competing alternatives, this is a matter for careful decision-making by knowledgeable stakeholders. Only by unlikely coincidence will the public interest be served by transmission plans dictated by legislation or based on comprehensive visions devised from afar. Our focus is on the planning, cost allocation, and siting processes and criteria by which important transmission investment decisions should be made.

Consistent with this focus, the Federal Energy Regulatory Commission's (FERC) July 2011 Order No. 1000 required improved coordination in transmission planning and cost allocation procedures within planning regions and between neighboring regions.[8] (The Order does not define "region," but notes that planning regions are smaller than the two larger interconnections and larger than single utilities.) We believe the Order is a step in the right direction but that the public interest would be best served if affected parties went beyond the order's minimal requirements. Moreover, FERC's limited authority prevented it from addressing the problem of siting transmission facilities that cross state boundaries or federal lands. We argue that this process, too, needs reform.

4.1 TRANSMISSION DEVELOPMENT IN THE U.S.

Between 1980 and the late 1990s, annual investment in the U.S. transmission system declined in real terms, and many observers expressed concern that the system was becoming economically inefficient and unreliable.[9] A careful analysis of available data suggests that this concern was mostly unwarranted.[10] Transmission and distribution losses generally declined over this period (see Figure 1.4), and there is no quantitative support for assertions of diminishing reliability. Moreover, since the late 1990s, investment in transmission has increased considerably, and these earlier concerns are less often heard today.[11]

The transmission system is not broken, and there has been and continues to be substantial investment in system upgrades and new interconnections. Today's grid meets today's requirements, but new and different demands are driving the expansion and adaptation of the transmission grid and the evolution of its supporting institutions. The system can and will respond to the new forces, but effective response will require material changes in the regulatory and policy framework.

Drivers of Expansion

U.S. transmission projects traditionally have been categorized by the primary purpose they serve: reliability, economic efficiency, or generator interconnection.[i] Public policy purposes—for example, to meet renewable generation targets—have recently emerged as a fourth category, and they are explicitly recognized in FERC Order No. 1000. While these labels are common, in practice, increased transmission capacity will provide the system with multiple benefits that may change over time. While it has been convenient to label a transmission line according to its primary purpose, this convention is at odds with the new reality and could be both confusing and counterproductive. Any transmission line serves all these purposes to different degrees. In the future, coherent policy for analysis of costs and benefits should recognize and capture this interaction. Aggregation across the benefit categories should be the norm in evaluating transmission lines.

FINDING

Transmission lines routinely serve a variety of purposes with many categories of benefits. Aggregation across benefit categories should be the norm in evaluating transmission lines.

Reliability is the most common justification for transmission investment in the U.S. Transmission projects are developed either to meet reliability standards promulgated by the North American Electric Reliability Corporation (NERC) and regional reliability authorities or to accommodate uncertain future growth and development without violating those standards.[ii, 12] The benefits of reliability are difficult to quantify and are often asserted to be spread over relatively wide areas.

[i] As a general matter, it is important to recognize that non-transmission investments can sometimes serve the same purpose as transmission investments and that transmission investments do not always take the form of new towers and wires on new rights-of-way.[13]

[ii] A discussion of the reliability standards that are used to govern generation and transmission investment decisions is beyond the scope of this study. For the discussion in this chapter, we take them as given. However, the criteria underlying current reliability standards do not necessarily reflect rigorous cost–benefit analyses, an issue FERC is addressing.[14]

Only after reliability planning is complete do planners look for investments that would increase economic efficiency. Economic benefits include reduced network losses and mitigated or eliminated capacity constraints (generally termed "congestion") that prevent the use of the lowest-cost set of generators to meet demand. By strengthening the transmission network, these projects also allow wholesale electricity markets to expand geographically, which mitigates market power and may provide other benefits. Of course, lines justified by economic benefits generally improve system reliability and vice versa.[iii, 15]

Economic planning processes are generally not nearly as well developed as the procedures for reliability planning, and many regions are still in the process of completing their first studies of economic opportunities.

Recent years have seen very few transmission lines built that had been justified primarily on the basis of economic benefits.[16] The stringency of reliability requirements may ensure that most available economic benefits are captured by lines built primarily for reliability, and a persuasive economic case for investment is difficult to make in the current recession. In addition, while the most basic economic benefits are in principle easier to quantify than the economic value of reliability benefits, measuring them in practice is a challenging analytical task (see Box 4.1).[17] Economic planning processes are generally not nearly as well developed as the procedures for reliability planning, and many regions are still in the process of completing their first studies of economic opportunities.

In the end, clear technical procedures for justifying reliability investments have generally ensured that all the lines necessitated by reliability are built, while lines justified primarily by economic benefits are rare.[18] Yet we cannot identify specific situations in which lines with clear economic benefits were planned but could not be built, perhaps because economic benefits have been too narrowly defined.[19]

Generator interconnection lines allow generators to connect to the most appropriate point on the transmission system—usually the closest. Historically, such lines have been short and largely uncontroversial, and they have been included in proposals for new generating capacity. However, if companies develop large solar and wind plants at locations far from the existing network, the equivalent generator interconnection lines may be longer and more expensive than in the past. As a result, current treatment of these lines and required reinforcements elsewhere in the network may need revision.

Indeed, as renewables receive increasing amounts of attention in public policy debates, there is growing concern that current transmission development procedures may not adequately support their development. Reflecting this concern, the concept of including public policy purposes as a justification has emerged in some regions and has been endorsed in FERC Order No. 1000. California, Texas, Colorado, and Minnesota have already established practices that account for policy objectives, and California ISO, Midwest ISO, Electric Reliability Council of Texas (ERCOT), and Southwest Power Pool (SPP) have planning

[iii] This point is well illustrated by Midwest ISO's 2009 transmission expansion plan, which included $4 billion worth of exclusively reliability lines that were expected to provide nearly $3.4 billion in economic benefits.[20] Midwest ISO's systematic assessment of these investment benefits is unusual, though. The frameworks for assessing the economic value of these reliability upgrades tend to be either very weak or nonexistent in most regional transmission organizations.

BOX 4.1 THE CHALLENGE OF ASSESSING ECONOMIC BENEFIT

Justifying investment in transmission to improve the economic efficiency of the power system requires a calculation of the economic benefit of that investment. The separate but related problem of appropriate cost allocation also presents significant challenges for transmission expansion. Unless project proponents can persuasively argue that the benefits are likely to outweigh the costs, and the costs and benefits have been fairly apportioned among the affected parties, it will be difficult to move a project forward in the face of inevitable opposition in the siting process. Neither problem has a simple, one-size-fits-all solution, but as we discuss in subsequent sections, reasonable and workable solutions do exist.

At the most basic level, the economic benefit of any project is measured by the increase in consumer surplus plus producer profits from the project. In planning, this translates into forecasting future demand and finding the change in the least-cost way of reliably meeting that demand that the project would make possible. Allocation of project costs should be based on benefits to market participants—both consumers and generators. Note that these benefits will be negative for consumers in low-price areas who, unlike most residential and other small customers, face location-specific rather than area-average prices when transmission congestion isolating them is alleviated. Benefits are also, symmetrically, negative for generators in high-price areas when a new line increases the linkage with areas with lower electricity prices. A more comprehensive view of transmission-related benefits is given in the "Planning Criteria" section on page 87, where planning criteria are examined.

Benefits assessment is complicated in practice by the fact that transmission affects not only electricity prices, but jobs, local interests, and the environment. In addition, large transmission projects often add important flexibility to the system over the short and long term. Planners and stakeholders need to determine which benefits to consider, how to value some hard-to-quantify outcomes of transmission development, such as the economic value of reliability improvements, and what approach will be taken to determine the "optimal" solution.

Beyond the particulars of quantifying benefits, assumptions about future environmental policies, generation resource additions and retirements, technological change, and relative fuel costs are grounds for debate, a complication that is made all the more problematic by the long lives of the assets involved. To assess their benefits, new lines can be compared to a counterfactual situation in which the line or set of lines has not been built. This is not practical with lines that were built a long time ago because defining the counterfactual would require the hypothetical untangling of all the subsequent investments and assumptions regarding what would have been built instead of the line in question.

processes that allow for public policy benefits. FERC Order No. 1000 will require that all local and regional transmission planning processes include policy objectives. It also mandates that public utility transmission providers establish procedures to identify transmission needs driven by public policy requirements and evaluate alternative ways of meeting those needs.

Some projects to deliver renewable power will not increase reliability, nor will they necessarily bring economic benefits until state or federal policies sufficiently reduce the cost of renewables or increase the cost of fossil-powered generators. However, the policy dimension can be made commensurable with economic and reliability benefits for purposes of evaluating transmission investments.

Transmission Investment

During and following the processes of transmission planning, it is necessary to determine who will invest in and build the new line and how its costs will be recovered. These processes take place primarily at the state or regional level in coordination with the states' public utility commissions. FERC plays a role as well: electricity transmission is generally assumed by law to be in interstate commerce and thus subject to FERC regulation because it takes place in an interconnected high-voltage grid that crosses state lines.[iv]

Some projects to deliver renewable power will not increase reliability, nor will they necessarily bring economic benefits until state or federal policies sufficiently reduce the cost of renewables or increase the cost of fossil-powered generators.

In regions without an ISO, the local vertically integrated utilities will each centrally plan transmission expansion as part of an integrated resource planning process. Once the plan is approved by the relevant state utility commission, the utility builds and maintains the lines that have been proposed and recovers the total cost—including an allowed rate of return on the investment—through state-regulated retail rates. When lines connect two utilities, the division of costs between them is negotiated and, after approval by the state regulator or regulators, each recovers its share of costs through its own retail rates.

Regions with an ISO have more latitude for different investment schemes because multiple parties may own, build, and operate transmission assets. In most cases, utilities and ISOs identify needed network improvements, and a transmission utility builds and maintains the project. In some jurisdictions, the transmission builder is always an incumbent—a transmission company that already has a presence in the region. In others, non-incumbents may propose projects. The project costs are allocated to network users based on a wholesale transmission tariff, proposed by the ISO or utility and approved by FERC, and the corresponding retail tariffs. In other cases, the conditions are appropriate for voluntary or "merchant" transmission investment, in which costs are typically recovered through contracts between the transmission owner and specific users who benefit from the investment. Voluntary funding of large-scale transmission projects is uncommon, however. Tariff-financed projects undertaken by non-incumbents are also rare in the U.S., but this may change as the FERC implements Order No. 1000, which lowers barriers to their participation.[22]

The idea behind merchant investments is to create new transmission capacity where significant locational price differences or important network constraints exist that the new line will reduce or eliminate once it is in service.[v] Alternatively, investors may try to cover their costs by arbitraging the differences in the locational marginal prices between the two ends of the line. But because transmission investments are lumpy, respond to reliability

[iv] Alaska, Hawaii, and the ERCOT region of Texas are exceptions. In addition, about one-third of the high-voltage transmission system in the 48 contiguous states is owned by government enterprises, cooperatives, and other entities not subject to FERC regulation.[21] These entities have much higher shares in some regions. The legal and policy problem of harmonizing their behavior with that of the entities regulated by FERC is complex and important, but it is beyond the scope of our study.

[v] The corresponding contract rates may be similar to those that result from standard regulatory processes, although they also may be higher because merchant investors are not prevented from seeking a high rate of return when bargaining with beneficiaries.

criteria, and have scale economies, they tend to reduce price differences substantially, making it difficult for investors to cover their costs in this fashion.[23] Would-be merchant investors may find it difficult to reach an agreement with enough beneficiaries willing to help cover the cost of the line. The few merchant projects that exist or have been proposed are mostly sponsored by new entrants and generally involve high-voltage direct current (dc) technology (discussed in Chapter 2), which allows the owners of the facility to capture a larger portion of the line's benefits through their ability to control power flows, which makes it easier to define the beneficiaries.[24]

4.2 TRANSMISSION PLANNING

As noted in Appendix A, in the early years of the industry, transmission planning was the responsibility of vertically integrated utilities that met their native loads from their own generation. Some interconnection linking these utilities occurred before World War I, however, and interconnection accelerated thereafter. Today, about two-thirds of the U.S. load is served by large, regional ISOs that plan transmission to serve projected loads in their territories. The planning processes vary significantly among different ISOs and non-ISO regions, but they focus primarily on the objectives of maintaining a transmission grid that is reliable and, with lower priority, economically efficient.[25] ISOs, power marketing administrations, and vertically integrated utilities do little joint planning, though this is changing as interconnection increases over time. Because NERC regional entities (see Figure 1.3) are responsible for reliability throughout their geographic domains, individual vertically integrated utilities within the same NERC region tend to have similar planning processes.

The planning process in most ISO regions is significantly more difficult than within vertically integrated utilities because decisions about the installation of new generation are the result of market forces (modified by state and federal support for renewables and other policies) rather than centralized planning. Thus, transmission planning in these regions is subject to additional uncertainties about where future generation may locate and how power will flow around the network, especially when renewable generators are involved.[26] Magnifying this effect are uncertainties regarding future subsidies and requirements for renewable generation, because a painful fact of transmission planning is that it typically takes much longer to plan, get approvals, and build a high-voltage transmission line than a wind farm or solar generating facility. When generator build times are shorter than those for transmission, planners are forced to either anticipate new generation and build potentially unnecessary infrastructure or wait for firm generation plans before starting the process and thereby potentially discourage new generation investment.

Interregional Transmission Planning

Until recently, ISO regions and states had worked together to negotiate specific interregional projects but had not developed formal interregional planning processes. But the Eastern and Western Interconnections are becoming more tightly coupled, and considering interregional projects one at a time rather than as parts of an interconnection-wide plan is no longer sensible. Indeed, without such planning, problems could arise that would impede efficient expansion of renewables generation. The U.S. Department of Energy (DOE) Eastern Wind Integration and Transmission Study, which considered wind penetrations of 20%–30% in the Eastern

Considering interregional projects one at a time rather than as parts of an interconnection-wide plan is no longer sensible.

Interconnection, demonstrates that even in scenarios prioritizing local wind, transmission requirements span multiple operating regions.[27] Further, the study concludes that reaching very high penetration of renewables will require substantial use of local and remote wind resources, which in turn will require accompanying transmission development within and across multiple regions.

The scale and complexity of the Eastern and Western Interconnections are such that interconnection-wide planning requires a hierarchical approach encompassing bottom-up and top-down processes. Bottom-up planning is the process of integrating local or regional transmission plans that are based on detailed knowledge of local or regional conditions. Top-down planning involves a central body charged with identifying potentially desirable inter- and intraregional lines. Both have shortcomings: A solely bottom-up approach will fail to identify potentially desirable lines that traverse regional boundaries. To capture these potential investments, one needs top-down processes, performed as part of interregional, and perhaps interconnection-wide, planning exercises. But a purely top-down process may not be adequately responsive to regional issues or planning processes. A hierarchical hybrid of the two approaches has the potential to respect local and regional needs while still having vision broad enough to recognize interregional opportunities.

The Western Interconnection has long been a leader in wide-area transmission planning using a hierarchical approach. In the Western Interconnection, members of the Western Electricity Coordinating Council (WECC), the NERC regional reliability council responsible for the Western Interconnection, collaborate to model economic transmission expansion through the Transmission Expansion Planning Policy Committee (TEPPC), which spans the entire interconnection.[28] While TEPCC and its subcommittees model the strategic economic expansion of high-voltage lines, smaller subgroups model reliability and lower-voltage lines.[vi] With American Recovery and Reinvestment Act funds, the council also has recently started an electric transmission planning study for the entire Western Interconnection, although this research activity may or may not influence what actually gets built.

In the Eastern Interconnection, both the PJM Interconnection and SPP have bottom-up subregional planning processes to supplement their top-down regional planning processes.[29] In addition, the Northeastern ISO/RTO Planning Coordination Protocol among ISO New England, New York ISO, and PJM has been in effect since 2004. But, until recently, the East has not had an interconnection-wide institution comparable to the TEPCC in the West.

By comparison, the European Network of Transmission System Operators for Electricity (ENTSO-E) has been tasked with providing a 10-year pan-European transmission expansion plan and has recently finished its first preliminary report.[30] This plan is not mandatory, but a directive establishes that national plans should be consistent with the pan-European one. The newly created Agency for the Cooperation of

[vi] For example, to plan transmission for the state of Colorado, the Public Service Company of Colorado participates in TEPPC, the regional transmission planning group WestConnect, the Colorado Coordinated Planning Group within WestConnect, and state planning procedures.

Energy Regulators is responsible for supervising this consistency and for reporting any significant deviation to the European Commission. Recently ENTSO-E has started to develop a longer-term strategic plan that will provide a vision for how a pan-European power system could develop sequentially over a time horizon to 2050.[31]

FINDING

In the Eastern and Western Interconnections, interconnection-wide planning, which has become more important, requires a hierarchical approach encompassing both bottom-up and top-down processes.

Two recent developments may serve to expand the effective scope of hierarchical wide-area planning in the U.S. Title IV of the Recovery Act appropriated $80 million to establish interconnection-wide planning collaboratives with the goal of "facilitating the development of regional transmission plans" and providing assistance in the form of "modeling, support to regions and States for the development of coordinated State electricity policies, programs, laws, and regulations." The Office of Electricity Delivery and Energy Reliability at the DOE issued awards to five separate organizations, two each in the Eastern and Western Interconnections and one in ERCOT. These organizations are made up of regional planning authorities from across each interconnection, but their effectiveness and impact on what actually gets built remain to be determined. Moreover, because of the nature of their funding, the new collaboratives are only supported for a single round of analysis and may well disappear afterward.

FERC urges transmission facility owners not subject to its jurisdiction to participate in these interregional planning processes, though it cannot require them to do so.

In a second development, FERC's Order No. 1000 requires regional and interregional planning between adjacent regions.[32] "Region" is undefined in the order, but it is noted that a single utility cannot constitute a region for this purpose. There are no requirements at the interconnection level, however. FERC urges transmission facility owners not subject to its jurisdiction to participate in these interregional planning processes, though it cannot require them to do so.

While existing planning arrangements have enabled construction and ongoing expansion of a reliable and efficient transmission grid, extensive use of renewable resources distant from major load centers will require stronger, permanent interconnection-wide planning procedures, particularly in the East. The West has demonstrated that this can be accomplished collaboratively. It may not require another layer of authority or bureaucracy, though some central staff and modeling capability will presumably be required to perform the top-down analysis necessary to complement existing bottom-up processes, as well as an agreed-upon definition of planning criteria, a prescribed periodicity of the plan, transparency, and adequate stakeholder participation. In addition, problems of planning methods and data availability will need to be addressed. We discuss these next.

FINDING

Making more use of remote renewables in an efficient manner will require permanent planning processes at the interconnection level.

Transmission Planning Methods

Transmission planning involves discrete and long-lived modifications to complex networks in the face of an uncertain future. More technically, transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed. These characteristics are compounded and the challenges magnified when planning over larger areas and trying to achieve multiple objectives. The current state of the art in transmission planning is able to address power systems on an ISO level, including moderate levels of uncertainty on a scenario basis.[33] However, current methods have not dealt with planning over the larger geographic areas and with the increasing levels of uncertainty that must be considered to integrate substantial renewable generation efficiently.

Transmission planning is characterized by a large number of choices with multiple dimensions, a great deal of uncertainty, large investments, and long periods over which investments must be assessed.

Today, the transmission system is planned using expert judgment supported by technical models. The general procedure is to forecast demand 5–10 years into the future and simulate the system performance at that time. Complex simulations identify reliability issues and potential economic improvements. If the simulations indicate a problem, system reinforcements or other remedies are developed. Next, the simulations are re-run to ensure that the reinforced system meets the prescribed reliability requirements and delivered energy costs are reduced.

Because the transmission system is a complex network, many possible reinforcement options can resolve system concerns. In contemporary transmission planning, experts frequently define the set of possible reinforcements. Expert planners tend to consider one investment at a time, however, rather than focus on system outcomes. Some optimization techniques are in principle capable of producing system plans without this limitation, and they have been used in some systems for a long time, although they have limitations of their own.[34]

Restructuring and the ensuing separation of transmission and generation planning will increase uncertainty. As noted above, the impact of uncertainty surrounding plant location is often compounded by the mismatch between generation and transmission build times.[35] Moreover, because load characteristics and locations, fuel prices, environmental policies, and generation portfolios may vary substantially over the 50-year lifetime of transmission investments, the network must be designed to perform well under a variety of different conditions.

To evaluate a network design's robustness, planners perform multi-period analyses under uncertainty, which allow them to consider investments that may not be deemed prudent during short time frames but may enable the efficient evolution of the grid in the long term. Performing such analyses for a complex network subject to multi-dimensional uncertainty is a computational and conceptual challenge, however, and little work has been done to develop methods to support robust network planning. Forward-looking studies often consider only the design of networks for a static year and single scenario.[36] These analyses do not yield an optimal expansion path to the eventual desired network, nor do they consider robustness to situations in which the envisioned scenario does not unfold.

Scenario methods, which consider multiple futures, have been used in some cases.[37] But scenario methods may not identify important regulatory and other uncertainties regarding the availability of renewable resources.[38] Because increased uncertainty cannot always be dealt with adequately via deterministic or scenario processes, stochastic planning criteria, tools, and methods will need to be developed by the industry and the research community, and then employed.[39]

Finally, to improve planning methods for wide-area networks, detailed data used by transmission operators on real wide-area networks must be available to use for testing. For a variety of reasons, including security concerns, such data are not generally available for this purpose today.[40]

FINDING

Currently available data and planning methods are not adequate to support interconnection-level planning that takes appropriate account of uncertainty.

Planning Criteria

As noted earlier, explicit criteria for transmission planning include NERC and state reliability standards and, in many regions, economic efficiency. In states or regions with requirements for renewable generation, public policy goals also play a formal role. Additional criteria are often left implicit and may include robustness and flexibility, expansion of wholesale markets and mitigation of market power, and the ease of constructing transmission in different localities.

In cases in which the criteria are unclear, conflicts can arise between system planning processes and policy requirements. The most obvious conflict today can occur in states with renewable portfolio standards but no transmission initiatives beyond the typical general requirement to provide transmission access. These states may fail to meet their renewables requirements for want of transmission, or they may meet them using unnecessarily low-quality, high-cost resources. Transmission to serve renewables will not materialize without appropriate policy requirements. Uncertainty regarding future support and requirements for renewables coupled with the mismatch between generation and transmission build times make such adverse outcomes more likely.

FINDING

States or regions with policies driving growth in renewable generation but that do not establish public policy goals as a clear criterion in transmission planning initiatives, may fail to meet their renewables requirements for want of transmission.

Some authorities have recognized this problem and established explicit transmission directives, such as the Renewable Energy Transmission Initiative (RETI) in California and the Competitive Renewable Energy Zone (CREZ) planning in Texas. In RETI, for instance, the criteria for assessing lines include the quality and quantity of the renewable energy resource accessed, the commercial viability of the renewable energy accessed, the environmental impact of a new line, and the proposed line's ability to bring renewable energy to market as opposed to relieving congestion. The RETI and CREZ criteria are detailed, which creates transparency and allows stakeholders to see why particular transmission expansions were studied and adopted.[41] These initiatives may be possible models for broader multistate or national initiatives.

4.3 TRANSMISSION COST ALLOCATION

As discussed earlier, cost allocation differs by market type. In regions served by vertically integrated utilities without organized wholesale markets, transmission costs are generally recovered across the utility's entire territory through regulated retail rates. The costs of lines that cross boundaries between regions are divided between the two regions in a manner negotiated specifically for each project.

But in ISO regions with wholesale markets, most transmission costs are recovered from network users through a separate charge. This shift from utility-by-utility allocation has severed what had been a clear association between specific transmission assets and the generators and loads they served. To date, the ISO regions have not yet converged on common principles of cost allocation, nor have they instituted consistent cost allocation procedures across or between regions.[42]

Even so, some generalizations are possible. In most ISO regions, regional cost allocation is performed differently for projects that serve primarily reliability, economic efficiency, and generator interconnection purposes. Costs of projects justified solely on reliability grounds are usually recovered on a uniform basis from electricity users. This general approach is commonly referred to as "socialization" of costs. Individual users' shares of total costs typically depend on total or peak consumption.

The costs of projects justified primarily on economic grounds are sometimes allocated in whole or in part to those end users who benefit most from their construction, and any remaining costs are socialized.

The generator involved tends to pay for generator interconnection projects. However, this is not done in a consistent fashion. Projects that are necessary to reinforce the network because a new generator is being connected may be allocated to loads and treated like reliability or economic upgrades. On the other hand, even the costs of radial lines connecting generators to the grid are often refunded to generators through regulated rates over time.

As we noted earlier, if intensive use is made of the best renewable resources, new generator interconnection lines and related system upgrades are likely to be more expensive on average than they have been historically. In addition, interregional lines probably will be more important. The corresponding cost allocation rules and processes will be under scrutiny and modification due to FERC's Order No. 1000 mandate that regional transmission planning processes must designate one cost-allocation method for all utility transmission providers and neighboring regions must have a common interregional method.[43]

Rather than proposing a specific cost-allocation method, we next lay out some fundamental principles that complement and extend the FERC order and then explore their application to the transmission planning process.

Principles of Cost Allocation

An important policy challenge is to develop principles and procedures for mandatory cost allocation. Participant funding for various forms of merchant lines or sale of capacity rights on large dc lines provide other cost allocation models. The common feature of these alternatives is that they are voluntary. Voluntary participant funding is desirable when it is workable. However, in many cases, the scale and scope of transmission investments can have a material effect on market conditions and create concerns over free-riding that would be impractical to overcome through strictly voluntary agreements. Thus, there is a requirement for regulatory approval and the associated mandatory rules for allocation of the costs.

None of the principles we present here conflicts with FERC Order No. 1000, but strict adherence to them would go beyond the order's requirements.

Principle 1. Costs should be allocated in proportion to benefits. This is the most fundamental principle. Each beneficiary's share of a project's costs should be as close as practical to its share of the project's total benefits.[vii] In principle, beneficiaries are any network users who see a change in their expected expenditures or profits as a result of the project, taking into account the value of increased reliability and any other benefits.[44] This so-called "beneficiary-pays" principle has been widely accepted in the U.S. and abroad. It stands at the core of FERC Order No. 1000, which in ¶585(1) states, "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits." We see no principled reason not to take this one step further: the allocation of costs should be *exactly* proportional to those estimates if the planning process has produced a set of estimates of expected benefits. This stronger language would avoid an interpretation permitting cost allocations that depart materially from the pattern of estimated benefits.

A transmission project is economically justified if its benefits exceed its costs. By reducing or eliminating price differences, however, a transmission project could impose losses on generators in previously high-price areas or on load in previously low-price areas. In addition, these projects can affect the economic value of any existing transmission rights and contracts (see Box 4.2), and some entities might suffer losses because of environmental harm. Regulators can cut through this tangle of effects by approving any project with positive net benefits, even if it imposes losses on some entities. They should disapprove projects with gross benefits for some that exceed costs but with negative net benefits overall. This means turning down some projects for which those who receive benefits would be willing to cover the costs.

Dividing a project's costs among network users in proportion to their benefits is generally perceived as equitable. And if a project's benefits exceed costs, all beneficiaries will be better off and less likely to oppose progress on the project.[viii] Conversely, if a project's costs exceed its benefits, it will be impossible to

[vii] Large, discrete transmission investments can have a material effect on prospective market prices and the distribution of benefits, and the associated costs are largely fixed *ex post*. Rather than recover those costs through ordinary transmission tariffs, it is better to use a multipart charging mechanism that couples *ex post* efficient usage pricing (reflecting congestion and marginal losses) with fixed access charges, assigned to members of the coalition of putative beneficiaries in a way that preserves net benefits for being a member of the coalition.

[viii] In principle, if the project has positive net benefits, it is possible to compensate any losers for their losses and make all affected entities better off. In practice, this is complicated and seldom, if ever, done. It is generally argued that compensation is not deserved for the loss of economic benefits (high prices to generators, low prices to loads) that exist only because of network congestion, but major environmental impacts may raise more serious issues in the future. Such impacts might be claimed, for instance, if a proposed line would cross a particular state but confer no benefits on its residents.

BOX 4.2 FINANCIAL TRANSMISSION RIGHTS

In an electricity transmission network, the laws of physics dictate that power flows distribute across all possible paths between locations, approximately minimizing total system losses. This creates strong interactions between generators and loads. One implication is the need for a central system operator who oversees generator dispatch and maintains balance in the system while respecting the many transmission constraints. Another implication is that there is no workable definition of "physical" transmission rights that would allow for individual generators and loads to arrange their own trades and determine the final dispatch of the system.

Organized electricity markets overcome these problems and support competition by supplementing decentralized trading with a coordinated and centralized final dispatch built on the framework of bid-based, security-constrained, economic dispatch with locational prices. The prices reflect the locational marginal values of generation and load.[45] The difference in prices between any two locations is equal to the marginal cost of transmission between them.

This definition of the marginal cost of transmission does not require separating transactions to describe the complex physical flows between locations. The difference in locational prices is charged as the short-run price of transmission. Users of the transmission system pay this price for explicit bilateral transactions or implicit trades through the coordinated dispatch.

The difference in locational prices also provides a means to define an economic alternative to the missing physical transmission rights. This is the financial transmission right (FTR) that allows the owner to collect the difference in locational prices for a given volume between two points. Users of the system pay, and owners of the FTRs collect. The economic effect is the same as would be true if it were possible to define and use separable physical rights. But the integrity of the FTR does not depend on the actual use of the system corresponding to the distribution of FTRs. In effect, the set of FTRs operates as though there were a set of fully tradable and reconfigurable physical transmission rights.

For a given transmission grid, if all the FTRs awarded are simultaneously feasible, the revenues collected from the system users will be sufficient to cover the payments to the holders of the FTRs. This is an inherent property of economic dispatch and the related locational prices.[46] For transmission expansions, the simultaneous feasibility rule applied to the existing plus incremental FTRs awarded with the expansion would guarantee the same property going forward.

An inferior but commonly used alternative to the beneficiary-pays principle is the socialization of cost, which spreads it uniformly throughout a region.

allocate costs in such a way as to make all entities better off. Thus adopting the beneficiary-pays principle helps with decisions about what should be built, as well as determining who should pay for what is built. Fairness is important, but support of consistent incentives for investments is the key reason for embracing this principle. Of course, failure to recognize all beneficiaries—the generators, in particular—could cause a beneficial project not be built because not enough of the benefits have been captured to cover the costs.

An inferior but commonly used alternative to the beneficiary-pays principle is the socialization of cost, which spreads it uniformly throughout a region. Socialization eliminates locational signals, reducing the system's ability to promote investment in the best locations. For instance, all else equal, socialization would always favor the best wind or solar resources, regardless of their location and impact on transmission costs. Additionally, spreading costs too widely may reduce cost discipline and eliminate the incentive to consider economic alternatives to transmission expansion.[47] One solution might be to socialize the costs of the alternatives, too, but doing so would call for significant changes in decision-making in the electric system and put many important investment decisions into the hands of regulators. Finally, uniform region-wide cost recovery can provoke substantial public opposition to even highly beneficial new investments if some parties are forced to shoulder costs that significantly exceed the benefits they realize.[ix]

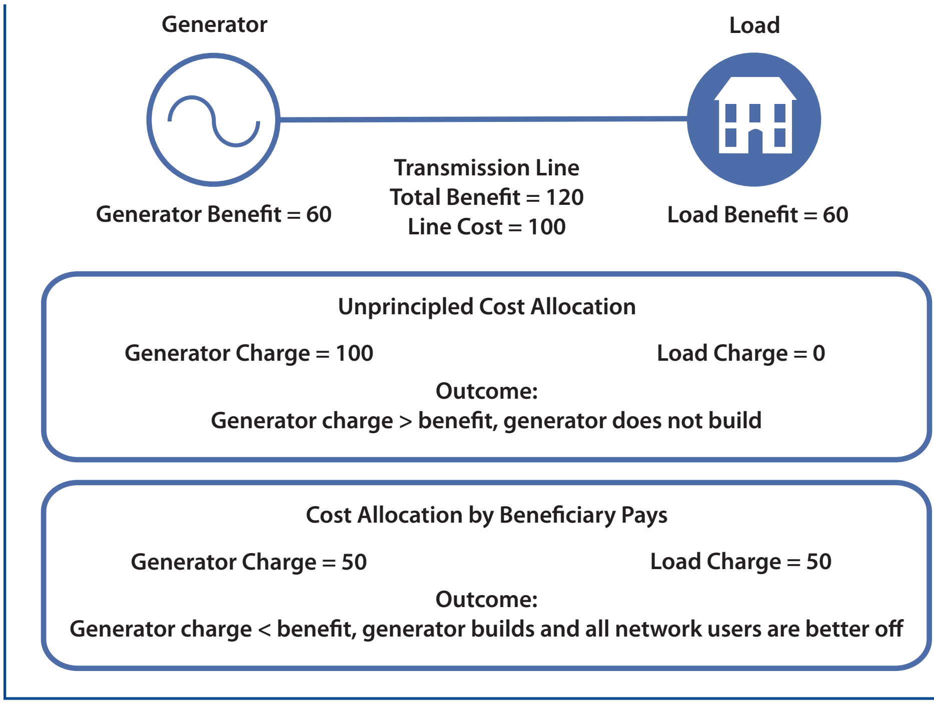
It is sometimes argued that cost socialization is a workable approximation when much uncertainty exists in the estimation of beneficiaries, or when the investment impacts several regions. However, this argument misleads. Great uncertainty about benefits and beneficiaries generally implies that expected benefits are widely distributed. The beneficiary-pays principle is still applicable, even though it might produce a cost allocation similar to direct socialization. But this would not be the same as abandoning the principle, nor would it produce the same result in the more common cases where significant uncertainty about some beneficiaries is accompanied by less uncertainty about others.

Where there are wholesale markets for electricity, generation and load generally are both beneficiaries of new transmission capacity. Generators use the transmission system to deliver their product, benefit financially from doing so, and should therefore be responsible for paying for a fraction of the network costs. Load also benefits from new transmission through reduced energy costs, increased reliability, or both. Cost-allocation procedures should seek to apportion the costs of a line to generation and load proportional to aggregate economic benefits realized by the two groups. As in any highly competitive market, if wholesale markets are highly competitive and there are no special opportunities for any generator to capture extra rents, all costs levied on generators will end up being passed on to load via wholesale electricity prices, either in the short or in the long term. This is true even if network charges are levied as an annual lump sum or on a per megawatt basis rather than per megawatt-hour of produced energy. In some markets, however, some generators may enjoy unique location-specific or other advantages, so they will retain benefits from transmission that is built to these locations. Moreover, not all generators operate in highly competitive environments, and changing market conditions typically provide multiple opportunities to generators to enjoy short-term rents (and suffer short-term losses), so these generators can be charged transmission costs without any anticipated pass-through to consumers.

If regulation fails to allocate costs according to benefits generated and, for instance, the cost of long interconnection lines is charged 100% to the generators involved, socially beneficial investments in generation could be abandoned, as shown by the illustrative example in Figure 4.1. Likewise, allocating too much of the transmission cost to load would eliminate locational signals to generators, especially for renewables that require costly transmission investments. These signals help to ensure that the most economically sensible sites are chosen for generator development.

[ix] This danger is illustrated clearly by PJM tariff submissions, which show a divergence as large as $1.2 billion in cost-allocation outcomes of a specific project for socialization compared to the PJM DFAX flow-based method.[48] While DFAX is not a perfect application of the beneficiary-pays principle, it does employ one commonly employed proxy for benefits. The Florence School of regulation has provided a useful comparative analysis of cost allocation methods.[49]

Figure 4.1 Illustrative Example for Generator Cost-Allocation Outcomes



All this stands in contrast to some current procedures, in which, for instance, generators are at least initially responsible for the entire cost of radial interconnection lines, while load entirely bears the cost of other network reinforcements. Regulators should be aware of the link that exists between the economic value of any subsidy to renewables and the decision of how much to charge these generators as a function of their economic benefits.

Any transmission planning exercise should look for investments with the largest margin of aggregated benefits (or reduction in system costs) over additional network costs. A sound planning process must provide sufficient information on the identities of the beneficiaries of proposed transmission investments to enable those proposals to be evaluated. Conceptually, this information can be used to allocate costs according to the beneficiary-pays principle. Transmission is inherently about moving electric power between locations, and the analysis of the value of such investment requires calculation of locational impacts on generation and load. A consistent parsing of the benefits, with careful consideration of the geographic scope of benefits from increased reliability, allows for estimation of cost shares that make the beneficiaries better off while respecting the principle that those in regions who do not benefit do not pay. This approach can yield a workable approximation to a beneficiary-pays allocation and make cost socialization a last resort.[50]

Principle 2. Transmission charges should be independent of commercial transactions. Regardless of any specific, pre-arranged commercial electricity trades, the physical flows on the network will remain unchanged, and loads will always be served by the least-cost set of available generators that does not violate any network constraints. Because commercial transactions have no influence on the physical network flows, charges for network use should not depend on individual commercial transactions. Instead, transmission charges should depend only on the location of the network users within the system and on when and where power is injected and withdrawn from the system.[51]

According to this second principle, a generator located in a region A that trades with a load-serving entity in a region B should pay the same transmission charge as if, instead, it were contracted to supply a neighboring load sited within its own region—and vice versa. The existence of any contracts voluntarily signed by any agents should not affect application of this principle because they should modify neither the physical real-time efficient dispatch of generation nor the pattern of demand. This second principle is not tantamount to socialization of network costs; as indicated before, transmission charges should depend on the location and the timing of network utilization.

When planners fail to separate transmission charges from commercial transactions, the result can be pancaking, a situation in which network users are required to pay accumulating fees in every region their power is deemed by contract to pass through, regardless of actual power flows. As a result, transmission charges depend on the number of administrative borders between buyer and seller. Such pricing tends to stifle trade and prevent buyers from accessing low-cost sellers. Furthermore, linking benefits calculations and contracts creates perverse incentives for entering into contracts to avoid cost allocations. This could lead to inefficient transmission investments and would significantly complicate operations in networks. The U.S. and the European Union have recognized that pancaking is undesirable; in response, FERC issued Order No. 888 providing open access to the transmission system and the EU developed a standardized mechanism for accessing and paying for the transmission system.[52] Today, transmission charges generally are independent of commercial transactions within U.S. ISOs, but not in inter-ISO transactions. This principle should also be applied in inter-ISO transactions.

One possible argument for pancaking is that it can enable compensation to some losers from a transmission project. Consider a line connecting regions A and B that crosses region C but provides no benefits within it. The generators and consumers in A and B who benefit from the line should pay for it. One might argue that residents of C will bear the environmental impact of the line and thus are entitled to charge for the transmission of electricity through it. While one can argue that compensation is justified in this case, that argument does not rationalize the wholesale distortion of transmission charges that pancaking implies.

Transmission charges should depend only on the location of the network users within the system and on when and where power is injected and withdrawn from the system.

Principle 3. The allocation of costs should be established *ex ante*, before the project is built. Once costs have been allocated on the basis of anticipated benefits, that allocation should be left in place for the life of the project—or at least a long period on the order of a decade. There is no reason to update a long-term price signal soon after a project has been completed because that project's investors have already responded to the signal and committed to action. The possibility of future updates adds uncertainty and raises capital costs.

Moreover, it is possible and necessary to evaluate a transmission investment *ex ante*, defining the net benefits as the difference in expected benefits with and without the investment, but there is no comparable method for *ex post* evaluation of benefits. A feature of network interactions is the strong interdependence of power flows. After projects A, B, and C have been built in order, for instance, it makes no sense to consider benefits *ex post* in a hypothetical network with B and C but without A because as a general matter the presence of

A will have affected the designs of B and C as well as the decisions to build them. *Ex ante* calculation of expected benefits is necessary for analyzing a decision to go forward with an investment, and the same calculations can support *ex ante* cost allocation. By contrast, *ex post* calculation is neither easy nor required for sunk investment decisions, nor is there a principled framework for parsing benefits in an interconnected grid.

Applying this principle sometimes requires judgment, as when significant uncertainty about future benefits is expected to be resolved in the relatively near term. For example, the imminent location of a large generating plant might have a material impact on the expected distribution of benefits. In such cases, it may be most sensible to allocate cost after the uncertainty is resolved rather than risk imposing costs well in excess of *ex post* benefits on some parties. Current transmission cost-allocation methods in some interregional markets, such as in Central America and the EU, have adopted this approach.

Once costs have been allocated on the basis of anticipated benefits, that allocation should be left in place for the life of the project—or at least a long period on the order of a decade.

Applying these principles perfectly is difficult in practice. But unless one begins with sound principles and departs from them only to the extent required by practical considerations, the final system of cost allocation will lack coherence, and the resulting pattern of investments is likely to be inefficient.

FINDING

To achieve an efficient and reliable network, three cost allocation principles should be followed as closely as possible:

- **Costs should be allocated in proportion to benefits.**
- **Transmission charges should be independent of commercial transactions.**
- **The allocation of costs should be established *ex ante*, before the project is built.**

Cost Allocation in Practice

In practice, the process of determining who benefits and how much they benefit is analytically complex, especially because of uncertainty regarding future benefits.[53] In addition, the lumpiness and economies of scale of transmission lines means that it is often sensible to build facilities with excess capacity in anticipation of future needs. This may provide economic justification for at least partial socialization of many projects during the early years of their operational lives, when they are not operating at full capacity. If a portion of capacity is put in place to serve potential future users, it may be sensible to socialize the costs for the early years of operation until those users appear.

Cost-allocation procedures are only workable if they are roughly compatible with voluntary agreements by the parties involved. The three principles of cost allocation form a sound foundation on which mutually beneficial agreements can be constructed. Recognizing that the first of them—the beneficiaries-pay principle—can have somewhat different operational meanings in different settings, we present some very general guidelines for allocation of intraregional transmission network costs:

- Maintain current transmission network charges for existing lines, and apply the cost-allocation method only to new or recently built lines.[x]

- For any new potential generator, estimate the benefits of recently built lines and lines that are scheduled to enter in service shortly. Any existing transmission capacity expansion planning procedure should be helpful in the evaluation of the benefits of new transmission facilities, and generators that have been built recently or are planned to be built soon have an impact on the network expansion plans.

- Use this information to compute the transmission charges for recently installed and prospective generators and loads, as well as for the remaining network users.

Even gradual implementation of these guidelines should move transmission tariffs toward a more cost-reflective—and thus more economically efficient—structure.[54]

Cost-allocation procedures for interregional, interconnection-wide, and renewable generation projects are even less developed than those for intraregional projects. But they will become more important in the future if large-scale renewable generation is substantially expanded.

Interregional or Interconnection-Wide Cost Allocation. FERC's Order No. 1000 calls for the development of standardized interregional planning and cost-allocation procedures. The result could be either common interconnection-wide procedures or a set of bilateral or multilateral cost-allocation agreements within each interconnection.

The former might emerge from discussions among planning regions or be imposed by FERC. An interesting example of such a procedure is the European Inter-TSO Compensation Mechanism.[55] This mechanism uses network flows as a proxy for benefits and deals only with the allocation of costs between regional system operators (TSOs in European terminology). Planners first employ flow-based methodologies to determine how much external agents use the network of each region. Then they calculate the costs associated with that usage and allocate them to the corresponding external regions. The net balance is credited or charged to each region, and its network users pay based on that region's chosen tariff method. This hierarchical scheme provides a workable (if imperfect) interregional cost-allocation system anchored in beneficiary-pays logic and leaves each regional operator free to define its own system for intraregional cost allocation.

On the other hand, it may be difficult as a practical matter for the many regional authorities involved in both the Eastern and Western Interconnections to reach agreement on this or any other common interregional approach. The alternative is a set of bilateral or multilateral cost-allocation agreements. This outcome would obviously lead to processes that would be more sensitive to regional differences, but such a system would be less adept at dealing with multiregional problems involving, for instance, loop flows. In this case, FERC might consider developing default procedures for multiregional issues in the absence of prior agreements among all affected parties.

[x] Our major concern is the allocation of the costs of new transmission investments. Transmission charges for the existing lines to new network users are of lesser importance to this study, but some practical implementation guidelines can be found in the literature.[56]

From these considerations emerge broad guidelines for sound interregional transmission cost-allocation procedures. Ideally, they should be applied globally within each interconnect:

- Apply cost-allocation method only to new transmission projects.
- Whenever possible, use an estimate of the project's benefits to allocate costs among the regions involved; if this is not possible, some measure of network usage might be used as a proxy for benefits.
- Use this information to compute the fraction of the cost of the project to be covered by each involved region.
- Allow each region to allocate the cost it must cover to its network users according to its own internal procedures, which should be built on the three basic principles presented here.

Remote Renewable Generators. When all generators were built by vertically integrated utilities, lines connecting the generator to the transmission grid were treated as (a generally small) part of the cost of the generator. Transmission cost differences were thus automatically taken into account in making locational decisions, but only in unusual cases, like mine-mouth coal plants, did they have much of an effect on those decisions.

In contrast, different entities may now build and own generation and transmission facilities, and the cost of interconnection lines and other required transmission network upgrades may represent a significant fraction of the cost of the remote, large-scale wind and solar plants that may be developed in the future. Under the traditional approach, the generator would pay the full project cost. But in the case of remote renewables, this is likely to represent a significant departure from the beneficiary-pays principle. That principle should be applied to determine cost allocations for interconnections of major system upgrades between major load centers and remote renewable generators just as for other transmission projects.

Two other issues associated with renewables development deserve mention. First, wind and solar power plants are often built in relatively small increments of several tens to a few hundred megawatts, typically substantially less than the standard sizes of conventional thermal power plants. This is true even in areas with good resources that may ultimately support many such plants. High-voltage transmission lines, however, are often most efficiently constructed at scales designed to serve a gigawatt of capacity or more. The effect of this mismatch is that large amounts of transmission capacity may not be used until more generation comes online in an area, which could take years. In the meantime, a relatively small generator could face the cost burden of oversized, under-utilized transmission system upgrades.

A second problem emerges because many of the best wind and solar resources are far from the existing transmission system. Transmission utilities have little interest in building capacity to remote areas far from the existing infrastructure, since it is generally unclear under current tariffs who would pay for such lines. As a result, transmission utilities would like to wait for generators to build first so that they can then finance the transmission upgrades necessary to accommodate these resources. Of course, generators will not build if their plants have to sit idle for years before they can interconnect to the grid and start to sell their power.[57] This is the classic chicken-and-egg problem with transmission.

There are creative approaches to address both problems. Initially, regions could allocate the cost of new transmission projects in remote areas where wind or solar development is anticipated to load. Then, as generators come on-line in these areas, they would assume their pro rata share of the transmission costs, even paying back consumers if appropriate. Eventually, if generators come on-line as forecast, the proper costs would be allocated to all parties, but costs would shift over time to ensure that initial financing challenges do not prevent utilities from building a beneficial line at efficient scale. In this way, planners can reduce the financial risk to transmission developers, and a lack of available transmission would not force generation investors to inaction. A risk is that the forecast is wrong, new generation does not appear, and the loads subsidize the costs. This is not strictly compatible with *ex ante* cost allocation, but it does involve a process that would be put in place *ex ante*, with well-defined steps.

California has instituted procedures of this sort, called location-constrained resource interconnection pricing, in its processes for developing in-state renewable resources.[58] Texas is using its CREZ planning, which involves socialized regional cost recovery, to address this issue.[59] The New York ISO also has dealt with this issue in its interconnection procedures by initially using a "class-year" allocation process to share the costs of transmission upgrades among numerous generators and establishing a headroom account whereby future developers reimburse the developer who has initially paid for the transmission upgrade. Yet another alternative approach is the coordinated procurement, or anchor tenant, model that the New England states are discussing.[60]

4.4 SITING NEW TRANSMISSION CAPACITY

When a developer attempts to build a transmission line, it must acquire necessary siting permits from some set of states, localities, and federal authorities to build the facility. During the siting process, projects are most vulnerable to challenge and litigation by parties who are not satisfied with the project for any reason. Shortcomings in planning or cost allocation can compound intrinsic difficulties with siting, such as NIMBY ("not in my backyard") complaints. Conversely, progress on transmission planning and cost allocation should serve to reduce disputes about cost allocation that surface in disguise during siting proceedings. A major test of this hypothesis would follow from implementation of the new planning and cost-allocation proposals in FERC Order No. 1000. It is hard to imagine, though, that siting will ever become routine: local protests and logistical troubles will undoubtedly persist to some extent.[61]

State laws and regulations primarily govern the approval process for siting transmission, though in some states, city and county authorities also may be involved. While recent decades have seen a steady movement toward greater transmission grid interconnection and regionalization, siting regimes have not kept up with this expansion in scope. The rules in one state may specify requirements different than in another that affects the same investment—e.g., requiring a specific route in Iowa and a set of alternatives in Illinois. And as Ashley C. Brown and Jim Rossi note, "There is a powerful economic incentive to be parochial in siting decisions."[62] This mismatch in scope compounds siting difficulties. If one hopes to build a line across multiple states or utility systems, limited provisions are in place to recognize the benefits of transmission that may accrue to neighboring systems.[63] This basic conflict is not unique to the U.S.; it appears in other large, hierarchically organized power systems.[64]

During the siting process, projects are most vulnerable to challenge and litigation by parties who are not satisfied with the project for any reason.

The current siting landscape in the U.S. encompasses a complex system of many stakeholders and administrative processes, each with its own interests and rules.[65] The plethora of authorities involved in transmission siting is well illustrated by a 2006 memorandum of understanding on transmission siting signed by five executive agencies, two regulatory bodies, the Council on Environmental Quality, and the Advisory Council on Historic Preservation.[66] Within the federal executive agencies, an additional 12 major subagency organizations are also cited as playing a significant role in the process.

At the local level, challenges take the form of individuals or communities objecting to the aesthetic or perceived health or environmental impacts of transmission infrastructure. NIMBY opposition has grown over time as concerns for fragile ecosystems, recreational land, and scenic or historic trails and parks have intensified. Nationally, the federal government controls about 30% of land in the U.S. and higher percentages of several western states. Obtaining approval to build a transmission line across federal land is never an ordinary commercial transaction, and federal agencies with a conservation mandate can strongly resist the construction of high-voltage transmission facilities. Even on land that is not federally controlled, projects to build new lines must undergo federal and state environmental reviews adhering to the National Environmental Policy Act, the Endangered Species Act, the Migratory Bird Treaty Act, and other laws.

Challenges can take years to resolve. In March 1990, American Electric Power announced its intention to build a 765 kilovolt line between Virginia and West Virginia that would pass through the Jefferson National Forest. Largely because of opposition by the U.S. Forest Service, final approvals were not received until December 2002. The line was energized in June 2006.[67] Another example is Public Service Electric & Gas Group's proposed Susquehanna–Roseland project, which would link Pennsylvania and New Jersey. The utility proposed a route in August 2008 after a detailed study and public workshops. New Jersey and Pennsylvania regulators have approved the project, but as of September 2011, the National Park Service has not.[68]

Siting permits and environmental reviews often have a limited shelf life and thus may lapse if other complications cause delays. In other cases, approval timelines for certain sections of a right-of-way may exceed those for others because of the differing siting authorities. Groups opposing a project can exploit the mismatch between processes.[xi]

Perhaps more than anything else, securing an authorization for a transmission project hinges on the determination of need, because state regulators are often required by political reality—and sometimes by law—to focus exclusively on in-state costs and benefits in making decisions.[69] The requirements to give priority to local need can be problematic even when there are stakeholders in a state that might benefit from the local development and tax base of the new transmission investment. For instance, in May 2007, Arizona regulators unanimously rejected Southern California Edison's proposed Devers–Palo Verde 2 line, which one commissioner described as "a 230-mile extension cord" pulling energy from Arizona to California.[70] They found that California ratepayers would benefit from access to Arizona's generating capacity, while Arizona rates would increase as a consequence of the increased demand. The increased cost for some due to expanded interstate commerce is a normal consequence of trade. Even without

[xi] The U.S. Chamber of Commerce maintains a useful resource that describes many of these challenges and includes a list of active transmission projects facing major hurdles (http://www.projectnoproject.com/category/project/transmission/).

affecting electricity prices, the focus on local need is an obstacle to development. For example, a transmission line that crossed a state like Arkansas without local interconnections might make sense, but the absence of local service could preclude a required demonstration of meeting a need under state law. If national policy is best implemented by bulk transfer of renewable power across long distances and across state lines, the existing state-centered siting procedures will likely prove to be a significant impediment.

Despite these impediments, many transmission projects have been planned, sited, and built in recent decades. Many of these do not cross state lines, and state authorities are responsible for approving them. ISOs' planning processes have also been successful in facilitating multistate lines that are justified by reliability considerations, simply because reliability problems will tend to affect all states within a region. Problems arise when projects serve economic or public policy goals and involve costs and benefits in multiple states or regions.

As regional institutions and processes have grown in importance, some states have gradually taken action to ease the siting process for lines that serve interests in multiple states. They have employed several mechanisms, including interstate cooperatives and joint transmission studies. For example, the Western Governors Association established a protocol in 2002 to set forth procedures for collaboration between siting agencies in the Western Interconnection. While this agreement did not contain specific siting provisions, it may serve as a basis for more detailed and binding future steps. Although differing in their details and execution, similar organizations exist in the Midwest ISO, SPP, and PJM with the purpose of understanding and coordinating transmission siting processes across the different states involved. These regional efforts are still works in progress, and being voluntary present real problems of fashioning agreements that compromise different interests of competitors.

If national policy is best implemented by bulk transfer of renewable power across long distances and across state lines, the existing state-centered siting procedures will likely prove to be a significant impediment.

At the federal level, the Energy Policy Act of 2005 empowered groups of states to form interstate compacts for transmission siting, though no such compacts have been formally recognized yet. More notably, this act also added the new §216 to the Federal Power Act, which gave FERC authority to issue permits for facilities in areas experiencing capacity constraints or congestion and designated by the Secretary of Energy as a National Interest Electric Transmission Corridor (NIETC). These permits would confer rights of eminent domain if a state commission or other entity with authority to approve siting has "withheld approval for more than one year after the filing of an application seeking approval."

However, subsequent Circuit Court decisions made §216 effectively irrelevant, ruling that FERC cannot act if a state simply rejects rather than withholds approval of a project it opposes and that the process to designate NIETCs was flawed.[71] In 2009 the House of Representatives passed a bill with a provision that would have empowered FERC to consider interstate projects rejected by state regulators, though only in the Western Interconnection.[72] A bill reported out of the Senate Committee on Energy and Natural Resources contained a broadly similar provision that would have applied in both Eastern and Western Interconnections.[73] Neither provision became law, and even if FERC had meaningful backstop authority within NIETCs, there now exist no legally designated NIETCs within which it could exercise that authority.

FINDING

Current siting procedures make it easier to obtain permission to build a transmission project located in a single state that does not cross federal lands than one that requires the approval of more than one state or a federal agency.

A range of other measures has been proposed to streamline the siting process and lower unnecessarily high barriers to transmission development:[74]

- Articulate best practices for reviewing siting proposals.
- Examine state legal frameworks to identify legislative language that may inhibit siting coordination and how that can be remedied.
- Broaden the definition of need that state commissions use to include energy efficiency, public policy, and out-of-state benefits.
- Develop common review processes between local, state, and federal authorities, including coordination of requirements and potentially a centralized siting agency.
- Coordinate and speed federal agency reviews. The interagency memorandum of understanding signed in 2006 is an example of action in this direction, as is the recently announced formation of an interagency Renewable Energy Rapid Response Team to ensure timely review of proposals to site transmission facilities on federal lands.[75]
- Increase regulation of the time allowed for permitting reviews at all levels.
- Establish or use existing regional institutions to facilitate interstate siting and standardize siting procedures.

Because existing transmission siting procedures are widely recognized as a hurdle to development, some of these reforms may be realized, at least in part. However, they are relatively modest and unlikely substantially to reduce obstacles that arise because responsible state agencies serve the interests of their in-state constituents at the expense of others and federal agencies pursue mandates that give little weight to an efficient and reliable bulk power system. State and federal agency officials may be doing their assigned jobs well yet acting against the broader national interest. This structural problem is unlikely to be solved without effective structural change.

An analogous problem arose within states in the early years of the grid's development.[76] The early technology for electric transmission emphasized local development of generation and limited (or no) longer-distance interconnection. Local authorities held sway over need determination and the siting process. As conditions changed and the impact of transmission grew to cover larger areas and loads, state governments began a slow and incomplete process of centralizing decisions within the state and preempting local authorities, all in pursuit of the broader state-wide interest. The same technical process continues with longer-distance transmission, increasing interconnection and even broader regional and national goals—but now the role of individual states, not to mention local governments, has changed against the backdrop of this broader reach of proposed transmission investments. The parochial interests of the states and localities, which are easy to understand, do not naturally encompass the broader interests of larger regions or of the nation as a whole.

The parochial interests of the states and localities, which are easy to understand, do not naturally encompass the broader interests of larger regions or of the nation as a whole.

We have also seen this process before in the case of natural gas. In 1938, Congress recognized that a similar structural problem could substantially retard the development of interstate natural gas pipelines and passed the Natural Gas Act. Section 7(h) grants FERC authority to evaluate proposals for such pipelines. Since a 1947 amendment to this Section, if the FERC approves a proposed pipeline, the company building it receives the right to acquire the necessary property by eminent domain if it cannot acquire it on negotiated terms.[77] While this procedure may not be optimally designed or perfectly administered, it does not generate either intense controversies or unreasonable delays compared to the analogous challenges of electricity transmission expansion.

The problem of siting interstate electric transmission facilities was not important in 1935 when the Federal Power Act was passed, and it was not addressed in that legislation. It is important now and, as we have argued, in large part because of the growing importance of remote renewables, it will likely become more important in the future. Improving regional, interregional, and interconnection-wide analysis and planning would help. Implementing a workable, beneficiary-pays cost-allocation procedure within each interconnection would help. But even with perfection in these reforms, the competing interests of states would affect electricity transmission in the same way that conflicting state interest could have affected natural gas pipelines and other forms of interstate commerce. In the end, hoping that obvious structural problems will not retard desirable investment is not enough.

The simplest and most elegant solution to the problem of interstate transmission siting is to give FERC authority over significant interstate projects or those requiring land managed by another federal agency. One might want to depart from the natural gas model by limiting FERC's authority to projects that have emerged from regional, interregional, or interconnection-wide planning processes, as appropriate. Yet eliminating states' roles entirely has a variety of disadvantages given their superior knowledge of local conditions. Thus a workable alternative would be to amend §216 of the Federal Power Act to give the FERC effective backstop authority over these projects, anywhere in the U.S. This would involve eliminating the conceptually and administratively troublesome notion of NIETCs, allowing FERC to consider reliability, as well as economic and public policy benefits, while specifying that a state's denial of approval of a multistate project should serve as a trigger to FERC consideration.

While one can debate the merits of these alternative approaches—and we have done so within our study team—we agree that either the natural gas model or the FERC backstop approach would serve the national interest much better than the status quo.

4.5 CONCLUSIONS AND RECOMMENDATIONS

The current system for governing and financing transmission expansion has served the U.S. electric power industry well. However, this system likely will not be adequate in the immediate future, when large deployment of grid-scale wind and solar generation is anticipated and the transmission grid becomes more interconnected across state and regional boundaries. Because some of the best wind and solar resources are located far from major load centers, their efficient utilization will require permanent, effective interconnection-wide transmission planning processes.

These processes and associated institutions could be required by federal legislation, or FERC could extend the planning requirements in Order No. 1000 from regional and bilateral interregional levels to the interconnection-wide level, leaving the details of procedures and organization to internal industry agreements. Alternatively, the industry could see the logic and value of a broad, comprehensive approach to planning and voluntarily go beyond the order's minimum requirements.

RECOMMENDATION

To support the integration of large-scale wind and solar resources, improve system reliability, and increase efficiency, permanent hierarchical and collaborative processes should be established for conducting planning of interregional transmission projects at the interconnection level.

Unfortunately, however, available data and planning methods do not yet support rigorous interconnection-wide planning that adequately accounts for uncertainty, particularly in the more complex Eastern Interconnection.

The first need is to develop the necessary data and make them available to those who can use them constructively. This does not require the creation of a new agency; NERC's mandate could be broadened to include this function. Making detailed network data widely available would obviously raise security concerns, but in recent years the Census Bureau and other federal agencies have developed protocols for making highly confidential data available to researchers without compromising security. We believe similar protocols can be devised for bulk power system data.

RECOMMENDATION

A responsible entity should develop detailed and comprehensive data on the U.S. bulk power system and make them available to researchers and others under procedures that satisfy security concerns.

While we believe the development—and utilization—of better planning methods is important and an attractive area for academic research, we do not believe the necessary research is likely to be expensive by the standards of federal energy research and development projects. It could be funded by industry contributions to the Electric Power Research Institute, an ad hoc industry coalition, or a public-private partnership involving DOE.

RECOMMENDATION

The industry, the federal government, or both should support research to improve hierarchical, robust methods for wide-area transmission planning under uncertainty over multiple time periods.

To produce coherent outcomes, transmission regulation has to be a conceptually integrated system. Planning, business models, cost allocation, and siting are all interrelated, and a consistent approach to all is required to produce stakeholder support for an efficient and reliable system. In particular, as FERC Order No. 1000 recognizes, the criteria and decision-making process that are adopted for transmission planning need to be closely coupled to the subsequent cost-allocation process.

RECOMMENDATION

In the interest of producing reliable electric power at least cost, particularly while integrating large-scale renewable generation, transmission cost-allocation methods should abide by three basic principles:

- **Costs should be allocated as closely as practical in proportion to benefits.**
- **Transmission charges should be independent of commercial transactions.**
- **The allocation of costs should be established *ex ante*.**

Implementation of these principles will be a challenge, but the challenge can be met through application of the same tools used to perform cost–benefit analysis in transmission expansion planning. FERC's Order No. 1000 sets out the core principles. Those responding with compliance filings should apply the same information used to calculate expected benefits to the task of displaying the expected distribution of benefits that are inherent in the analysis of transmission projects, and the allocation of costs should in principle be exactly proportional to the expected distribution of benefits. While intraregional cost-allocation methods may differ somewhat, they should be compatible with these three principles.

Currently, rules for interregional network cost allocation do not exist. Thus, to accommodate renewable generation and the growing interconnectedness of the transmission system, it is important to develop an agreed-upon procedure for allocating the costs of projects that cross regional boundaries or have a significant impact on interregional trade. Ideally, each interconnection would have a single procedure rather than a maze of bilateral or multilateral agreements.

RECOMMENDATION

A hierarchical approach to interregional transmission cost allocation should be developed that uses a single procedure, respecting the three principles of the preceding recommendation, to allocate costs between regions. Each region then can cover the costs allocated to it using its own internal cost-allocation procedure, also in agreement with the three principles.

Like the first recommendation, this goes beyond the requirements of FERC's Order No. 1000. Federal legislation or a new FERC order could mandate this approach. Or the industry could see the advantages of having a single interregional cost allocation procedure and establish one voluntarily.

If investments in the transmission grid are to advance overall system efficiency and efficient integration of large-scale renewables, planning criteria, decision-making procedures, and cost-allocation methods must enable transmission projects that have justifications other than reliability to be built under appropriate business models.

Siting transmission facilities will always be a complex issue, but sound approaches to planning and cost allocation will make it easier. Even with these improvements, however, there are strong incentives for state agencies to ignore out-of-state interests and for managers of federal lands to give inadequate weight to the health and efficiency of the bulk power system. These incentives constitute barriers to siting interstate transmission facilities that serve the broader national interest, in particular by providing for the efficient integration of large-scale wind and solar generation.

RECOMMENDATION

The federal government should grant FERC enhanced siting authority over interstate electricity transmission projects or those that cross land managed by another federal agency. Such authority could broadly parallel its authority over interstate natural gas pipelines, or §216 of the Federal Power Act should be amended to give the FERC effective backstop siting authority anywhere in the U.S.

As we have discussed above, these two approaches have different strengths and weaknesses, but either would be a significant improvement over the status quo.

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Chapter 5: The Impact of Distributed Generation and Electric Vehicles

In this chapter, we discuss the challenges and opportunities associated with distributed generation (DG) and electric vehicles (EV). Supported by public policies reflecting a range of concerns and goals, these technologies are expected to increase in penetration over the next few decades. At high penetrations they may require systemic changes in the way the electric grid is planned and operated. The successful integration of growing penetrations of DG units and EVs primarily will be the concern of industry engineers. Similar to Chapters 2 and 3, this chapter provides important background and context for the chapters that follow.

Section 5.1 focuses on DG. It starts by defining distributed generation and describes recent deployment trends. It then describes the potential benefits of DG, followed by a discussion of the interconnection challenges related to DG. We introduce the primary interconnection standards for DG and discuss several potentially important modifications to the standards. These modifications are required to allow the full realization of several of the projected benefits of DG. Finally, we briefly describe several effects of DG on distribution system operations.

Section 5.2 discusses EVs. It begins by introducing the different types of EVs and recent forecasts of their potential penetrations over the next several decades. It then describes electric vehicle charging requirements and discusses the importance of influencing the timing of electric vehicle charging. We find that influencing the timing of vehicle charging could improve system operation and avoid investments in infrastructure upgrades that would otherwise be necessary.

Section 5.3 provides our conclusions and recommendations. We recommend that the main standard governing DG interconnection be revised to permit voltage regulation by DG units and that utilities provide incentives for off-peak vehicle charging in regions with high EV penetrations.

5.1 DISTRIBUTED GENERATION

Distributed generation refers to relatively small-scale generators that produce several kilowatts (kW) to tens of megawatts (MW) of power and are generally connected to the grid at the distribution or substation levels.[i] Distributed generation units use a wide range of generation technologies, including gas turbines, diesel engines, solar photovoltaics (PV), wind turbines, fuel cells, biomass, and small hydroelectric generators. Some DG units that use conventional fuel-burning engines are designed to operate as combined heat and power (CHP) systems that are capable of providing heat for buildings or industrial processes using the "waste" energy from electricity generation.[1] For example, our own institution, MIT, has a combined heating, cooling, and power plant based on a gas turbine engine rated at about 20 MW, connected to our local utility at distribution primary voltage (13.8 kV). Distributed

[i] It is important to note that distributed generation is distinct from *dispersed generation*, which is not connected to the grid. Dispersed generation is typified by standby diesel generators that provide backup power in the event of a grid failure. Because these units typically do not impact utility operation or planning activities, we do not discuss them. Though not connected to the grid, dispersed generators can participate in demand response programs (see Chapter 7).

Table 5.1 Theoretical Benefits of Distributed Generation

Reliability and Security Benefits	Economic Benefits	Emission Benefits	Power Quality Benefits
• Increased security for critical loads • Relieved transmission and distribution congestion • Reduced impacts from physical or cyberattacks • Increased generation diversity	• Reduced costs associated with power losses • Deferred investments for generation, transmission, or distribution upgrades • Lower operating costs due to peak shaving • Reduced fuel costs due to increased overall efficiency • Reduced land use for generation	• Reduced line losses • Reduced pollutant emissions	• Voltage profile improvement • Reduced flicker • Reduced harmonic distortion

Source: U.S. Department of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005* (Washington, DC, 2007); and P. Chiradeja and R. Ramakumar, "An Approach to Quantify the Technical Benefits of Distributed Generation," *IEEE Transactions on Energy Conversion* 19, no. 4 (2004): 764–773.

generation can be owned and operated by utilities or their customers and can provide a variety of theoretical benefits to their owners and the broader power system. Large DG units are typically dispatchable and communicate with system operators like central station generation facilities do. However, neither utilities nor system operators typically monitor or control the operation of small DG units, especially those in residential applications. Renewable DG from wind and solar power also typically is not dispatchable or easily controllable. These units present the greatest challenge and are the primary focus of this chapter.

Distributed generation can be owned and operated by utilities or their customers and can provide a variety of theoretical benefits to their owners and the broader power system.

In 2009, about 13,000 commercial and industrial DG units with a combined capacity of about 16 gigawatts (GW) were connected to utility systems in the U.S.[2] Of these units, 10,800 (83%) were smaller than 1 MW, averaging 100 kW each.[3] Internal combustion engines, combustion turbines, and steam turbines comprised more than 4 GW each of installed capacity, while hydroelectric, wind, and other generator technologies totaled 3 GW.[4] In the same year, 93,000 residential PV installations totaled about 450 MW of capacity.[5] While 90% of solar PV installations between 1998 and 2007 were smaller than 10 kW, the largest installations generated more than 14 MW.[6]

Federal and state policies are expected to drive growth in DG in the coming decades. Sixteen states and the District of Columbia currently have renewable portfolio standards with specific DG provisions.[7] For example, some states have provisions in their renewable portfolio standards that require some fraction of retail electricity sales to come from renewable DG by 2020.

Distributed generation advocates cite a litany of good things DG can do. Distributed generation installations theoretically can improve reliability, reduce costs, reduce emissions, and improve power quality (see Table 5.1).[8] However, the benefits of DG are highly dependent on the characteristics of each installation and the characteristics of the local power system.

Furthermore, many benefits accrue to specific stakeholders and may not benefit the distribution system operator or the other customers of the system. Finally, existing DG interconnection standards prevent owners from realizing some of these hypothetical benefits.

Improved system reliability results from the ability of DG units to maintain supply to local loads in the event of a broader system outage. This could be done by creating "islands" in which a section of a distribution feeder is disconnected from a faulted area. Such an action is called "islanding." Successful islanded operation requires sufficient generation to serve local loads and also the necessary distributed system control capabilities.[9] The potential reliability benefits of generators based on variable energy resources, generators with limited fuel reserves, or generators with low individual reliability are limited even if islanded operation is possible.

Economic benefits can be realized when utilities deploy DG to defer investments in transmission or distribution infrasturcture.[10] Since DG is typically located closer to load relative to central plants, it can reduce congestion and system losses in some instances.[11] Customer-sited DG, on the other hand, often reduces utility revenue but can offer customers long-term electricity cost stability and, in some cases, savings. This savings can come in different forms. First, current rules allow customers with DG to avoid paying their share of fixed network costs (See Chapter 8). Second, because electricity generated by DG installations is typically more expensive than electricity generated in central stations, customers subject to increasing block electricity tariffs (in which customers who use more than some amount of electric energy pay a high rate) or who are offered sufficient subsidies can realize energy cost savings with DG. Combined heat and power (CHP) systems also can reduce total energy costs for their owners.

Emission benefits can be realized by renewable generators, such as solar photovoltaics (PV), which have no marginal emissions, or CHP systems whose use of waste heat can result in higher efficiencies than central generation units.[12] The magnitudes of emissions benefits associated with DG depend on both the characteristics of individual DG units and the characteristics of the power system to which they are connected.

Distributed generation capable of providing constant, uninterrupted power can improve power quality by mitigating flicker and other voltage regulation problems. On the other hand, distributed generation connected to the grid via power electronic inverters (e.g., solar PV, fuel cells, and most wind turbines) are widely understood to be sources of voltage waveform distortion. However, if designed and implemented properly, the power electronics could theoretically cancel grid distortions and help regulate voltage.[13] Many inverters on the market today are capable of these advanced functions, but such features add cost, and today DG owners rarely have incentives to invest in this added functionality.[14]

At present installed costs, many renewable DG installations remain dependent on these mandates or subsidies. The durability of such government policies will largely determine the rate of growth of installations over the next several years. In the long term, cost reductions also may drive DG growth. The average installed cost of residential and commercial solar PV installations dropped from about \$10.50 per W_{dc} in 1998 to about \$7.60 per W_{dc} in 2007 (both figures are in 2007 USD before incentives or tax credits).[15] As of September 2011, residential, commercial, and industrial PV installed system costs had fallen to \$7.10, \$5.10, and \$3.70 per W_{dc}, respectively.[16] While these costs are not competitive with conventional generating sources in most locations, if they continue to fall, solar PV systems will ultimately become competitive. As described in Chapter 8, net metering policies that favor renewable DG could accelerate the adoption of residential rooftop solar PV generation even before this type of generation becomes otherwise economically viable.

FINDING

Distributed renewable generation, though becoming more cost competitive with conventional generation technologies, is still significantly more expensive and strongly dependent on mandates and subsidies for its economic viability.

Meeting Interconnection Challenges

The integration of DG presents new challenges for distribution system planning and operations, principally because the configuration of power lines and protective relaying in most existing distribution systems assume a unidirectional power flow and are designed and operated on that assumption. Historically, the penetration of DG was sufficiently small to be regarded as simply a reduction in load, but this will change if DG penetrations grow. While the physical wires and transformers can carry power flow in the reverse direction, DG nonetheless can have adverse impacts on system reliability, power quality, and safety.[17]

IEEE Standard 1547

In recognition of the potential adverse impacts of DG on distribution systems and the need for uniform criteria and requirements for the interconnection of DG, the industry collaborated with the Institute of Electrical and Electronics Engineers (IEEE) to create IEEE Standard 1547,[18] first released in 2003 and later incorporated into the Energy Policy Act of 2005.[19] The standard's primary intent is to ensure that DG units do not have negative impacts on other customers or equipment connected to the grid; it applies to the interconnection of all generation with aggregate capacity of 10 megavolt amperes (10 MVA, approximately 10 MW) or less to the distribution system.

The standard includes several provisions to mitigate DG's potential negative impacts on power quality. For example, the standard requires that DG not "create objectionable flicker for other customers."[20] "Flicker" refers to rapid variations of voltage that can cause noticeable variations in lighting and interrupt the operations of electronics. Flicker can occur, for example, when clouds pass by photovoltaic cells, rapidly changing their power output.[21] Solar plant operators can use energy storage, static volt-ampere reactive compensators, or other forms of reactive compensation to mitigate potential flicker problems.[22] Distributed generation connected to the system with inverters (as are all solar PV systems) could use advanced inverter functionality to provide this reactive compensation.

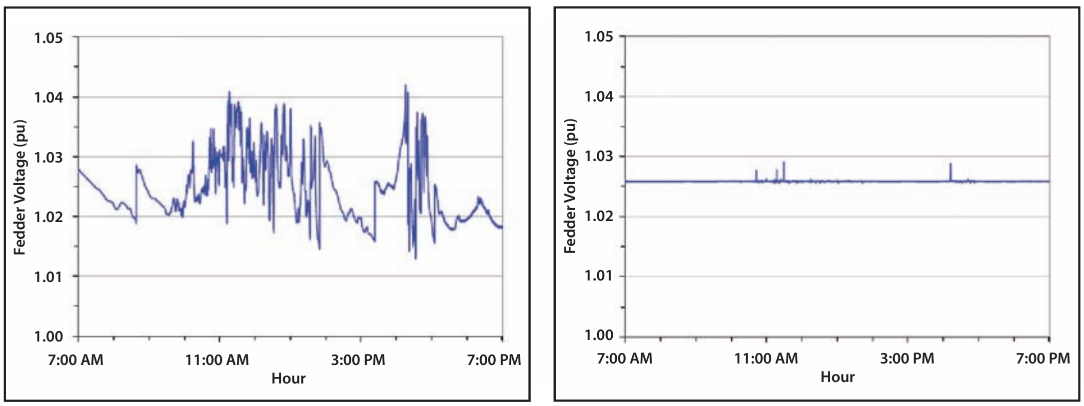
IEEE Standard 1547 also seeks to address potential safety issues with DG, as it would threaten the safety of utility workers were it to keep a line energized after a fault when the line is thought to be "dead."[23] The standard requires that DG units disconnect from the system when local faults occur or when the voltage or frequency at their interconnection point falls outside prespecified ranges. DG units are also required to detect unintentional islanding, circumstances in which DG supplies a local portion of the grid that has been disconnected from the bulk power system, and disconnect "within two seconds." While the standard does not explicitly forbid "intentional islanding," it does not specify requirements for islanded operation and indicates that islanding is "under consideration for future revisions" of the standard.

BOX 5.1 DISTRIBUTED GENERATION'S CONTRIBUTION TO VOLTAGE REGULATION

In a recent study, General Electric discusses the potential benefits of allowing distributed generation (DG) units to actively regulate voltage.[24] The study simulates a 10 megawatt (MW) solar photovoltaic (PV) system connected to a 13.8 kilovolt (kV) feeder whose peak load reached 12.3 MW. The system also had 600 kilowatt (kW) solar PV inverters that could simultaneously supply real power and produce or absorb up to 290 kV-amperes of reactive power in order to regulate voltage levels.

Figure 5.1 illustrates the significant difference in feeder voltage with and without voltage regulation observed in this study. As an additional benefit, allowing the solar PV system to regulate the voltage at its interconnection point was found to significantly reduce the need to operate other voltage regulation devices located along the simulated feeder. This result suggests that allowing DG units to actively regulate the voltage at their point of connection could sharply reduce voltage variation under high penetrations of DG. If such operation were to reduce the need for mechanical tap-changing transformers, installed to regulated voltage, it also would reduce maintenance costs. The results likely would be similar for more moderately sized DG units on low-voltage circuits.

Figure 5.1 Feeder Voltage at the Point of Interconnection of a Solar PV System



(a) Without Voltage Regulation Capability **(b) With Voltage Regulation Capability**

Note: The voltage scales on these plots are in a normalized measure called per-unit (pu). The normalizing constant is the nominal voltage of the line, 13.8 kV in this case. The line is operating at approximately 1.026 pu, which is 14.2 kV.

Source: ©2010 IEEE. Reprinted, with permission, from R. A. Walling and K. Clark, "Grid Support Functions Implemented in Utility-Scale PV Systems," paper presented at the Transmission and Distribution Conference and Exposition, 2010 IEEE Power & Energy Society, New Orleans, LA, April 19–22, 2010.

Since the original creation of IEEE Standard 1547, IEEE has supported efforts to create eight additional supplemental standards documents intended to extend and/or clarify the provisions in the main standard text.[25] For example, IEEE Standard 1547.4, completed in 2011, specifies the required capabilities of DG and necessary operating procedures that can be used to create intentional islands, thereby partially filling the previously mentioned gap in IEEE Standard 1547. While five of these documents have been completed, three additional documents are currently in development and are expected to be released over the next few years. IEEE Standard 1547 itself was reaffirmed without change in 2008 and is next up for revision in 2013.

FINDING

The potential negative impacts of DG on the power system are being mitigated by the establishment of interconnection standards through the IEEE.

Future Modifications to IEEE Standard 1547

Since its initial drafting, several weaknesses in IEEE Standard 1547 have become apparent. Grid-connected DG units, especially those based on variable energy sources, were not as prominent when IEEE Standard 1547 was first created as they are expected to be over the next 20 years. As the number of DG installations grows, modifications may be needed to ensure that the standard continues to address current state-of-the-art practices and needs. This section discusses several changes to IEEE Standard 1547 that should be considered if DG penetrations are to continue to grow.

Distributed generation can complicate the regulation of voltage across the length of distribution feeders.

Voltage Regulation. Distributed generation can complicate the regulation of voltage across the length of distribution feeders. But DG units connected to the grid via advanced power electronics also could play a role in actively reducing voltage flicker and regulating voltage levels at the point of interconnection (see Box 5.1). Power-conditioning modules within DG units that are capable of voltage regulation have improved considerably in recent years. However, IEEE Standard 1547 forbids DG units from actively regulating the voltage at their interconnection point.

Islanded Operations. IEEE Standard 1547 requires DG units less than 10 MVA to disconnect when an outage (or a large voltage drop) on the main system is detected. The standard requires disconnection in the event of unintentional islanding and does not discuss requirements for intentional islanding. In the development of IEEE Standard 1547, some argued that DG units should disconnect from the system to prevent damage to distribution system equipment and ensure the safety of utility crews repairing outages. The requirement that DG units disconnect during system outages effectively prevents DG units from providing reliability benefits to surrounding customers.

The recently released IEEE Standard 1547.4 discusses the intentional use of DG to supply power to a disconnected part of the distribution system when a fault is present in another part of the system. Distributed generation units that are connected to the grid in a way that complies with this standard should be capable of sustaining islanded operation and providing reliability benefits.

However, intentional islanding will require generators that are large enough to supply adequate real and reactive power to the island. It also necessitates distributed monitoring and control systems capable of maintaining local supply and demand balance as well as regulating the voltage and frequency within appropriate ranges. These monitoring and control capabilities add cost, and owners of very small DG units are unlikely to invest in this capability. Additionally, voltage and frequency regulation capabilities only are allowed in islanding operations and not when the island is reconnected to the distribution system. Therefore, even though IEEE Standard 1547.4 has been released, intentionally designed islanding schemes (for example, see Box 5.2) probably will be limited to larger DG units for the immediate future.

BOX 5.2 MICROGRIDS

Microgrids that are capable of separating from the utility system and operating autonomously as electrically isolated islands for extended periods of time can be formed by a part of the distribution network incorporating distributed generation, storage, uninterruptible power supplies, or a combination of the three.[26] Such capability may be desirable for customers or groups of customers that require unusually high reliability levels. Military bases, college campuses, hospitals, semiconductor manufacturers, and data centers are examples of customers with high reliability needs. Microgrids in island operation would ensure that customers within the island would still have electric power supplied to them despite a fault upstream.[27]

Microgrid R&D is still in the early stages. Of the 160 active microgrid projects encompassing 1.2 gigawatts (GW) of installed DG worldwide, the majority have been demonstrations and research pilots.[28] Microgrids are expensive because they require power electronics and sophisticated coordination among different customers or areas.[29] It is our sense that in most situations, the cost of configuring an area as a microgrid does not justify the reliability benefits, which may be achieved through other means, such as backup generators. Despite the challenges, microgrids have the potential to bring new control flexibility to the distribution system and thus will continue to receive much academic interest.

FINDING

Interconnection standards have recently been revised to allow for the realization of the reliability benefits of DG by permitting the operation of islanded distribution networks.

Active System Management

Distributed generation imposes new challenges on distribution systems that cannot be mitigated by modifying interconnection standards. The most prominent of these impacts is the ability of DG to disrupt the operation of system protection schemes.

Modern system protection schemes typically use multiple layers of coordinated protection devices, including circuit breakers and fuses, to interrupt current and short-circuit faults while affecting service to the smallest possible number of customers. These devices are set based on fault current levels and other characteristics of the local distribution network. Distribution networks today are typically designed using a "fit and forget" approach in which settings for protection equipment remain static.

Distributed generation units can increase current at a fault and reduce it at the protection device for the period before the DG senses the fault and disconnects, making it harder to detect a fault and complicating the coordination among protection devices.[30] In addition, fault currents at points of system protection will depend on which DG units are connected and operating at any given time. Changing fault currents with the introduction of DG could lead to unreliable operation of protective equipment and result in faults propagating beyond the first level of protection. The propagation of faults through system protection layers can reduce system reliability and safety.

In contrast to the passive operation approaches described here, new technologies promise to allow active management of distribution systems.[31] For example, it has been envisioned that utilities could use real-time information about the operation of the network and the nature of connected resources to dynamically change protective relay settings. Active management distribution system operation techniques, such as actively using DG and loads for voltage control and fault current level control, can also be used to reduce the costs of mitigating challenges related to regulating voltage profiles and ensuring adequate power quality with high penetrations of DG.

5.2 ELECTRIC VEHICLES

Similarly to DG units, electric vehicles could have a disruptive impact on the electric grid if not integrated carefully because they will connect to the distribution network to charge. As we discuss below, some such vehicles will represent a larger load than a house. The extent of their impact will depend on the degree and density of their penetration, charging requirements, and the time of day they are charged.

"Hybrid electric vehicle" (HEV) refers to a vehicle with an electric motor, an internal combustion engine, and limited onboard energy storage that improves fuel and engine efficiency. HEVs, such as the Toyota Prius, have already penetrated the automotive market. Automotive manufacturers are now turning to plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). PHEVs and BEVs have more onboard energy storage than HEVs and give owners the ability to charge the vehicle battery from a stationary electrical source—for example, an outlet in the garage. A PHEV contains an internal combustion engine, has a limited range in all-electric mode, and uses gasoline for long trips. A BEV has an electric motor, but no internal combustion engine, and it has a larger battery and a range longer than the all-electric range of a PHEV.

Electric vehicles could have a disruptive impact on the electric grid if not integrated carefully.

Table 5.2 Representative Electric Vehicles Available in the United States by 2012

	 **Tesla Roadster**	 **Nissan Leaf**	 **GM Chevy Volt**	 **Toyota Plug-in Prius**
Type	Battery	Battery	Plug-in hybrid	Plug-in hybrid
Electric Range	245 miles	100 miles	35 miles	15 miles
Battery Size	53 kWh	24 kWh	16 kWh	4.4 kWh
Onboard Charger	9.6 kW	3.3 kW	1.44 kW	1.44 kW
Quick Charger	16.8 kW	60 kW	3.3 kW	3.3 kW
Charging Time	6 hours (onboard) 3.5 hours (quick)	6 hours (onboard) 0.5 hours (quick)	10 hours (onboard) 4 hours (quick)	3 hours (onboard) 1.5 hours (quick)
U.S. Launch	March 2008	December 2010	December 2010	Spring 2012
Price (MSRP)	$109,000	$35,200	$40,280	$32,000

Source: Tesla Motors Inc., "Roadster Features and Specifications," http://www.teslamotors.com/roadster/specs; Nissan Motors Company Ltd., "Nissan Electric Leaf Car: 100% Electric. Zero Gas. Zero Tailpipe," http://www.nissanusa.com/leaf-electric-car/; J. Wiesenfelder, "Cars.Com Field Trial: Mobile EV Quick-Charging," *Kicking Tires*, July 26, 2011, http://blogs.cars.com/kickingtires/2011/07/carscom-field-trial-mobile-ev-quick-charging-.html; General Motors Company, "2011 Chevrolet Volt," http://www.gm.com/content/gmcom/home/vehicles/browseByBrand/baseball_cards/chevrolet/volt.html; General Motors Company, "Chevrolet Volt's 240V Home Charging Unit Priced at $490," press release, October 6, 2010, Detroit, MI, http://gm-volt.com/2010/10/06/gm-announces-chevrolet-volt-240v-charger-pricing-and-installation-service-provider; Toyota Motor Sales, USA, Inc., "Toyota Introduces 2012 Prius Plug-in Hybrid," press release, September 16, 2011, Richmond, CA, http://pressroom.toyota.com/releases/toyota+introduces+2012+prius+plug-in+hybrid.htm.

Note: "Battery Size" gives the energy storage capacity of the battery in kilowatt-hours. This parameter also provides a relative physical size of the battery—for a given battery chemistry, e.g., lithium-ion, the battery size is directly proportional to capacity. "Onboard Charger" is the power capability of the charger which is integral to the car. This is the rate at which the battery can be charged by the internal charger. "Quick Charger" is the power capability of an external (optional) charger. The quick charger can provide a more rapid charge than the internal charger, as shown by the "Charging Time" data.

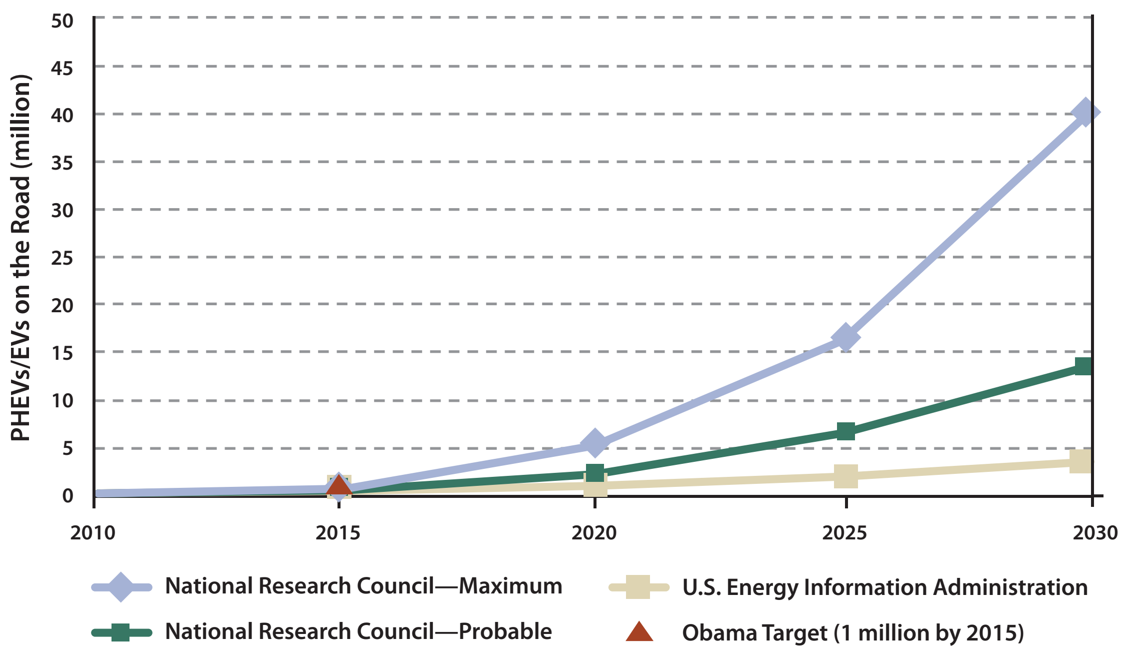
PHEVs and BEVs (collectively EVs) may emerge as a significant new distribution system load.[32] EVs as they are emerging today have batteries, usually lithium-ion, ranging in energy capacity from about 5 kilowatt hours (kWh) for short-range PHEVs to about 50 kWh for high-performance BEVs. By comparison, the Toyota Prius HEV has a 1.3 kWh nickel-metal hydride battery. Some representative EVs are shown in Table 5.2. As this table illustrates, EVs today are being designed with a range of specifications. Because BEVs have larger batteries, one would expect that they will be charged at considerably higher rates than PHEVs in order to limit the charging time, as illustrated by the table.

Degree and Density of Electric Vehicle Penetrations

The impact of EVs on the electrical system depends on their market penetration. Several past and ongoing studies attempt to estimate national EV penetration;[33] we illustrate four resulting projections in Figure 5.2.A carefully analyzed mid-range prediction from the National Research Council suggests that by 2030, 13 million PHEVs and BEVs, nearly 4.5% of the expected national fleet, could be on the road.[34] A projection by the U.S. Energy Information Administration (EIA) shows a substantially smaller penetration of EVs.[35] Of course, penetrations could be significantly higher or lower than these estimates depending on battery costs, gasoline prices, charging infrastructure, competition from other vehicles, and government policy. However, it is not the national penetration but the regional or local penetration that is of importance to utilities. The variances in estimates of regional and local penetration are also significant.

EVs will not initially be a concern for every utility. Varying geographic density of electric vehicles will mean that some utilities or regions

Figure 5.2 Projected Electric Vehicles on the Road by 2030

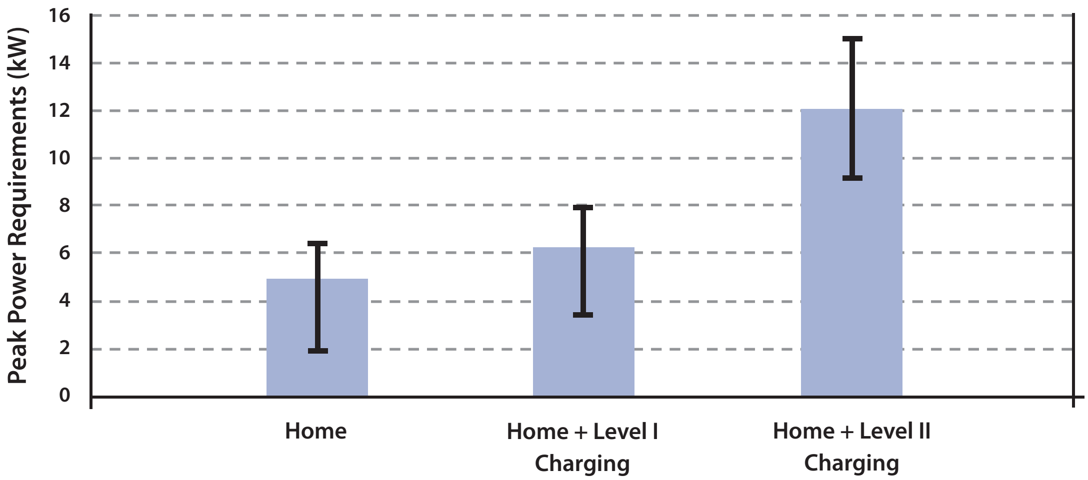


Source: Projection data from Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies and National Research Council, *Transitions to Alternative Transportation Technologies—Plug-in Hybrid Electric Vehicles* (Washington, DC: National Academies Press, 2010); Daily Compilation of Presidential Documents 2011 DCPD No. 00047, p. 3 (January 25, 2011); and U.S. Energy Information Administration, *Annual Energy Outlook 2011* (Washington, DC: U.S. Department of Energy, 2011).

BOX 5.3 HOUSEHOLD POWER AND ELECTRIC VEHICLE CHARGING REQUIREMENTS

Figure 5.3 compares requirements for vehicle charging to the average peak load of a single home near San Francisco Bay. The narrow vertical bar represents the variance in average home peak loads for locations throughout the San Francisco area. The broad bars show the peak power requirements for the same home by itself and with EVs charging at the two standard levels: 1.4 kW (Level I) and 7.2 kW (Level II).

Figure 5.3 Power Requirement of a Single Home in the San Francisco Bay Area with and without Electric Vehicle Charging



Source: Data from D. Bowermaster, "Plug-in Electric Vehicles and Their Impact: An Integrated, Multi-Stakeholder Approach," presentation at Environmental Quality Policy Committee Meeting, League of California Cities, Sacramento, CA, January 21, 2011, http://www.cacities.org/resource_files/29491.PGEPEVIntro(2011-01-18).pdf.

within utilities may be more severely impacted by the presence of EVs than others. Even within regions or utility footprints, only certain hotspots will need significant focus even in the medium term.

If the current geographic distribution of HEVs is a good indicator of demand for PHEVs and BEVs, distribution systems in California, Oregon, and Washington likely will experience considerably higher penetrations than average.[36] For example, Southern California Edison has projected a mid-case of 5% penetration, or 0.5 million PHEVs and BEVs in its service territory by 2020.[37] Even citing average penetration across a service area may understate the challenge, as PHEVs and BEVs may cluster in particular neighborhoods, thereby increasing concern for the local distribution system. Early integration problems are likely to arise most often when local demand rapidly increases because of uneven distribution of vehicles. Importantly, promotional policies, incentives, and the deployment of the necessary infrastructure will strongly influence the geographic distribution of EVs.[38]

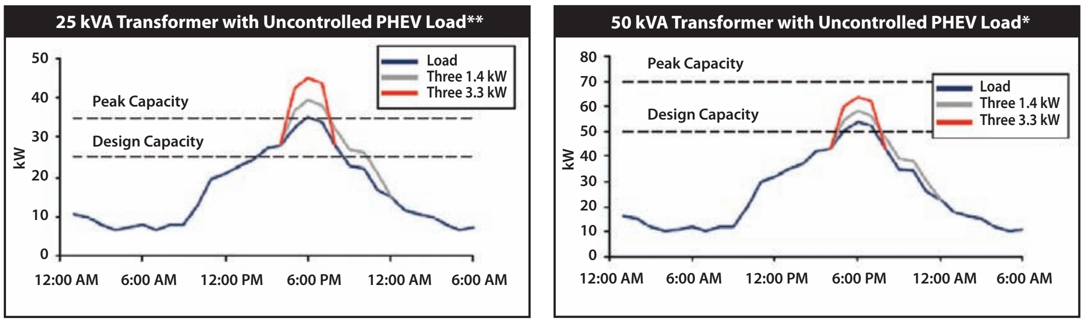
FINDING

Projections of EV penetration nationally are highly varied. However, some local regions are likely to experience penetrations much higher than the national average.

BOX 5.4 THE EFFECT OF UNCOORDINATED CHARGING ON TRANSFORMERS:

DTE Energy recently conducted a study on the impact of plug-in hybrid electric vehicles (PHEV) on distribution system components in its service territory. Figure 5.4 shows the impact on both a 25 kilovolt-ampere (kVA) transformer and a 50 kVA transformer of three PHEVs charging at two rates, 1.4 kilowatts (kW) and 3.3 kW, on a warm summer day. These transformers are loaded beyond their design capacity for both charging rates, and the 25 kVA transformer exceeds even its peak (short-term) capacity rating in both cases. This could lead to voltage dips, service interruption, and transformer failure.

Figure 5.4 Impact of Three PHEVs on Transformer Loading



(a) 25 kVA Transformer **(b) 50 kVA Transformer**

Source: J. LeBrun, DTE Energy, "Plug-in Electric Vehicle Overview," presentation at A Tale of Three Cities, webcast hosted by Intelligent Utility, January 6, 2011.

Electrical Vehicle Charging

EVs are expected to charge at one of three power levels. The Society of Automotive Engineers has established charging standards (in Standard J1772) that cover the following two charging power levels:

- Level I — up to 1.92 kW
- Level II — up to 19.2 kW

Level III has not yet been standardized in the U.S., but will enable full BEV charging within minutes.

At the residential level, the majority of PHEVs are expected to charge using Level I chargers, while BEVs are expected to charge at Level II. Charging BEVs will have more impact on the distribution system due to their higher-power charging and higher energy capacity than PHEVs. On the other hand, PHEVs are expected to comprise a majority of EVs, and a few PHEVs charging simultaneously could have an impact similar to one BEV. Therefore the potential impact of these two types of vehicles likely will be similar.

A study in 2008 estimated that if each North American Electric Reliability Corporation (NERC) region were to have a 25% penetration of PHEVs in the year 2030, each area would require less than a 5.5% increase in generation.[39] Aggregate power requirements are also unlikely to require significant upgrades to the bulk power system. If 25% of the national fleet were PHEVs, the power requirements could be up to 30% of generation capacity if simultaneously charged at 6 kW.[40] However, this increase is unlikely to materialize as there will be temporal diversity in the time of arrival at home and most charging will probably be at levels lower than 6 kW.[41] Nevertheless, there is some concern that EV charging could impact local distribution systems, requiring mechanisms to influence the timing of vehicle charging, discussed in the next section. Because an EV charging with a Level II charger is a bigger load than the average house, even a few EVs on a distribution feeder could overload that feeder and associated transformers (see Box 5.4).[42]

Influencing Electric Vehicle Charging

If electric rates do not vary over time, most EV owners will plug in their vehicles and begin charging when they arrive home each day, in many cases at the same time as neighborhood load peaks. This would exacerbate local peak load conditions, forcing utilities to invest in expanded infrastructure (see Box 5.5).[43] Early results from an ongoing Electric Power Research Institute (EPRI) project suggest that peak charging, higher charger power ratings, and increases in the number of EVs on a transformer could yield decreases in transformer lifetimes due to temperature-induced insulation aging from capacity overload.[44] The additional cost to the system of provisions for EVs would be a substantial but not dominant expense that most likely all system ratepayers would bear, though costs also could be recovered through higher fixed capacity charges (see Chapter 8) in neighborhoods where EVs required system upgrades.

Influencing the timing of vehicle charging can avoid these outcomes, reducing peak loading and improving load factor—that is, the ratio

BOX 5.5 VEHICLE-TO-GRID OPERATIONS

Some observers have suggested that the flow of energy between the power system and EVs could be bidirectional.[45] This concept is most often referred to as "vehicle-to-grid operation." While most often discussed in the context of vehicles providing frequency regulation services, in theory, energy stored in vehicles' batteries could provide various types of operating reserves. In regions with organized wholesale markets, it has been envisioned that vehicles could participate in frequency regulation or other reserve markets by supplying energy to the grid.

V2G operations would require substantial and expensive modifications to conventional unidirectional vehicle chargers and controls. V2G concepts also face other substantial technical challenges—degradation of battery life, OEM warranty issues, complexity and expense of added controls and communication with the utility, and the relatively small amount of energy involved if the battery is always to be sufficiently charged for driving the car—and are unlikely to achieve widespread deployment in the short term.

Beyond the technical challenges, the economic incentives for V2G operation also appear weak. In those markets with a regulation product, the price paid to participants for regulation services has historically been relatively low. The participation of EVs in these markets would likely cause the prices to decline further.

A more cost-effective alternative use of EVs would be to provide regulation or operating reserves only through control of their (unidirectional) charging rate—for example, decreasing their rate to provide up regulation, and increasing it for down regulation. While still requiring communication between vehicles and the utility, the charger requirements would be much simplified. This mode of operation would also have a much more limited impact on vehicle battery life. Particularly attractive is the use for this purpose of commercial EV fleets which have deterministic charging patterns.

between average and peak power. According to a 2002 study, if vehicle charging were influenced by policy or controls to produce a flat load between 6 p.m. and 6 a.m., the regional generation capacity could handle a PHEV penetration level from a low of 15% in California to a high of 73% in Texas.[46]

FINDING

For real-time pricing to be effective, EVs must be capable of automatically responding to price signals.

Two viable methods for influencing the timing of charging have emerged: time-differentiated tariffs and centralized charging control structures. Time-differentiated tariffs can be structured in a variety of ways: they can be static and based on time of use, or they can be signaled a day ahead, an hour ahead, or in real time. Vehicle owners might respond to time-of-use pricing by simply putting the vehicle charger on a timer set to avoid the most expensive times of day. If the time-of-use tariff were to have uniform timing over the whole system, a secondary peak load probably would develop at the time of price change.[47] Regulators might counter this effect by staggering the rate structure geographically.

A weakness of price signals for the distribution system is that they offer little insight into neighborhood congestion levels. As a result, time-of-day, period-ahead, and even real-time pricing would improve system-wide load factor, but are unlikely to have a substantial impact on feeder overloading. Utilities can more directly mitigate the impacts of EV charging on distribution circuits by remotely controlling charging. The exact mechanisms for accomplishing this in ways acceptable to consumers have not yet been fully worked out, but advanced metering infrastructure would help enable such a scheme.

The requirements include a tool to control charging power at each vehicle; a two-way communication link between the charging station and utility; and knowledge of the system state, the number of vehicles requiring charging, and the state of charge of each of those vehicles.[48] Controlling the charging of EVs may enable them to benefit utility operations by providing ancillary services such as frequency and/or voltage regulation (see Box 5.5).

FINDING

Using time-differentiated tariffs or central control schemes to discourage electric vehicle charging at peak times can improve system operation and avoid requiring capital investments in new infrastructure.

To give an idea of the effect, researchers simulated controlled and uncontrolled charging of an aggressive 75% penetration of EVs in the Netherlands.[49] They assumed two charging rates for the vehicles: 3 kW and 10 kW. In the uncontrolled case, owners would begin charging their vehicles on arrival at home, overloading 22.1% and 31.4% of the local distribution transformers at the 3 kW and 10 kW rates, respectively. The controlled charging case set charging rates to be inversely proportional to the historical load but ensured that enough energy was transferred to the vehicle for its next day's trips. With controlled charging, even this high penetration of vehicles would require upgrading only 1.9% of transformers.

Customer reactions to such a control scheme would be complicated and potentially negative. Implementing it might require a price break for participating customers and a mechanism for overriding the direct control at some cost.
In designing measures to influence demand, the differences between PHEVs and BEVs must be carefully considered. With their fuel-powered

engines, PHEVs offer their owners more flexibility in the timing of their vehicle charging, and owners may be more willing to take advantage of lower rates. By comparison, BEV owners may want to keep their batteries fully charged, charging when they have a chance, and therefore may resist methods that influence vehicle charging.

Controlling the charging of EVs may enable them to benefit utility operations by providing ancillary services such as frequency and/or voltage regulation.

The introduction of time-differentiated tariffs is not only being considered in the context of PHEVs and BEVs. As discussed in Chapter 7, demand response programs aim to shift total demand away from peak periods to realize both short-run operational benefits and long-run investment efficiency improvements. Electric vehicles could make these programs even more important.

5.3 CONCLUSIONS AND RECOMMENDATIONS

Distributed generation and plug-in electric vehicles are qualitatively different from the types of generation and loads that have been connected to the electric power system in the past. Widespread deployment of these technologies will change the requirements of the distribution system.

Growth in DG will arise from the economic advantages of cogeneration and policies that encourage distributed renewable generation, such as rooftop solar panels. IEEE Standard 1547 was a first attempt at establishing uniform interconnection criteria for small generators and included a range of provisions to mitigate many of the challenges associated with DG. However, as DG penetrations continue to grow, modifications to this standard will become increasingly important. In particular, adding provisions for islanded operation of DG units would permit them to enhance the reliability of supply, and enabling DG units to actively regulate the voltage at their interconnection points would ease the burden of providing uniform and constant voltage along distribution feeders.

RECOMMENDATION

DG interconnection standards should permit voltage regulation by distributed generators to enable them to help maintain distribution voltages within limits.

Growth in DG also will motivate the deployment of active distribution system management technologies, including the deployment of additional communication and sensors. Ultimately, deployment of these technologies could reduce the total costs of integrating high penetrations of DGs.

Plug-in hybrid and battery-powered electric vehicles, collectively referred to as EVs, have begun to enter the U.S. market. The number of EVs on the road in the U.S. by 2030 will depend on a number of factors that are difficult to predict. National projections range from as few as 3.3 million to 40 million by 2030. More important than the magnitude of penetration is the fact that it is not expected to be uniform across the nation because of state incentives, charging infrastructure availability, and consumer preference and income. In fact, EVs are expected to cluster in select high-income and eco-conscious neighborhoods. Between the two types of EVs, PHEVs will achieve greater penetration than BEVs due to their superior range and operational flexibility.

The degree to which EVs pose a stress to the power grid depends on their local penetration rate, as well as the power and time at which they charge. If regulators and utilities appropriately influence charging so that it mostly does not coincide with the system peak demand, EVs will improve system load factor and will not cause unmanageable disruption to the bulk generation and transmission system. Otherwise, integrating these loads will require more investment in equipment.

RECOMMENDATION

Utilities in regions with potentially high penetrations of EVs should explore mechanisms to incent off-peak charging.

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Chapter 6: Enhancing the Distribution System

In this chapter, we focus on the potential for new technologies to enhance the performance of distribution systems. New sensors, communication equipment, management systems, and automation and information technologies promise to improve the efficiency, reliability, and power quality of distribution systems.

Section 6.1 introduces technologies that promise to enhance distribution system operation. We describe the potential of more fully integrated distribution management systems, then introduce several new distribution system operation applications. These include automated fault detection, isolation, and restoration systems as well as voltage and power flow optimization systems. We find that many individual technologies that could enhance the distribution system are complementary, and the benefits from their deployment will be greatest when utilities use an integrated approach to system modernization.

Section 6.2 contains a more in-depth discussion of one particular distribution system technology: advanced metering infrastructure (AMI). We describe several categories of operational benefits of AMI and analyze the costs and benefits of AMI based on recent utility regulatory filings. We highlight the importance of the nonoperational benefits associated with AMI, to be discussed in more detail in Chapter 7.

Section 6.3 discusses the importance of learning from technology pilot programs and early deployments. The costs and benefits of new distribution technologies are subject to significant uncertainty. Detailed information generated from pilots and early deployments will enable utilities and their regulators to make more informed decisions on both investment priorities and system design.

Finally, Section 6.4 describes our conclusions and details this chapter's one recommendation. Recognizing the importance of data from distribution technology pilot programs and early deployments, we recommend that policy makers work to ensure that comprehensive data from Recovery Act–funded programs are shared as widely as possible throughout the industry.

The distribution system is the portion of the electric power system that carries power the few miles remaining between transmission substations and consumers. In addition to transporting electricity, the distribution system

- transforms voltage to the appropriate level for customer use;
- regulates voltages within a limited range;[1]
- detects faults and other abnormal situations on the distribution system and takes action to protect people and system components; and
- restores service following interruptions.

Today, less than 7% of total electrical energy in the U.S. is lost between generators and customers, and most of this loss occurs in the distribution system.[2] Reliability for individual customers varies widely, but averages in different regions of the U.S. tell us that customers can expect between 1.5 and 2 power interruptions per year and between 2 and 8 hours without power.[3] According to the relevant literature, 80% of interruptions are due to problems in the distribution system.[4] The

80% of interruptions are due to problems in the distribution system.

percentage of customer outage time attributable to the distribution system can be much higher in some specific cases; for example, the distribution system was responsible for at least 95% of interruptions[i] in the Southern California Edison service region from 2006–2009 and 92.6% of Florida Power & Light interruptions in 2009.[5]

Power quality refers to the degree to which voltage levels are accurate and constant, and the voltage waveform is a pure sinusoid. Power quality can be compromised by certain types of electrical loads as well as distribution system equipment. Distributed generators may contribute as well, as discussed in Chapter 5. Power quality issues generally do not cause problems with customer equipment because modern power supplies for phones, computers, televisions, and other electronics can accept a very large variation in voltage level and shape.

Providing efficiency, reliability, and power quality is expensive for utilities and ratepayers, but inefficiency and poor reliability also have costs. Up to a certain point, investments in system hardware represent a net gain to society. Beyond that level, additional improvements from investments may not be cost effective. The optimal level of service varies greatly depending on individual customer needs. An underlying principle in any discussion of new distribution investment should be that there is a trade-off between cost and level of service.

Measuring service quality is an important input to this assessment, but little attention has been paid to measurement, collection, and publication of standardized performance metrics across U.S. distribution utilities. Previous attempts to compile such data have highlighted differences in definitions and data collection processes.[6] More fundamentally, as of 2008, only 35 state public utility commissions (including the District of Columbia) required reporting of standard distribution performance metrics, though this represented an increase over a previous count in 2004.[7] Whereas European regulators have made a coordinated effort to regularly compile comprehensive data from distribution utilities across Europe and account for definitional and geographical differences,[8] no effort on that scale has taken place in the U.S. Improving these data could facilitate evaluation of investment opportunities going forward, as we recommend in Chapter 8.

6.1 OPPORTUNITIES IN DISTRIBUTION SYSTEM OPERATION

The integration of new communications infrastructures, sensor technologies, and advanced information technology will enable new distribution system capabilities over the next several decades. While many of these technologies have existed for some time, their deployment in U.S. distribution systems has been limited.

Utilities historically have employed a variety of manual or semi-automated systems to monitor system status, manage work crews,

[i] Percent of interruptions are calculated using SAIDI (system average interruption duration index) values. SAIDI, a reliability indicator commonly used by electric utilities, is the average outage duration for each customer served, usually measured in minutes per year. See the glossary for details.

detect outages, manage assets, manage infrastructure upgrades, and perform other tasks. Historically, a distribution system failure would be discovered when customers called the utility to complain about lack of power. Then the utility would send out a crew to track down and repair the problem. Some utility companies developed ad-hoc management systems to track and assign line crews. Lack of real-time instrumentation throughout distribution networks often limited the effectiveness of these tools, and standardization was largely nonexistent.

Distribution systems today are a product of this history. In many areas, today's distribution companies still employ essentially the same process for locating and managing outages as decades ago. In other areas, systems have evolved—but not always in the same direction, resulting in heterogeneous distribution systems around the country. This heterogeneity reflects the general lack of standardization as well as differences in geography and regulatory practices across state boundaries.

Recent advances in information and communication technologies have enabled the development of significantly more sophisticated distribution management systems (DMS) that can handle and fully integrate a wide variety of system management tasks. Beyond providing real-time visibility into the state of assets throughout the distribution system, state-of-the-art DMSs often can simulate distribution system power flows in near-real time, helping operators anticipate or respond to potential problems. For example, these systems can allow operators to determine whether changing the configuration of the distribution network in response to faults will result in a system with appropriate voltage levels and current flows. In conjunction with other technologies, modern DMSs promise to make distribution system operators more agile and responsive to real-time system conditions.

DMSs in use today run the gamut from modern to outdated. Surprisingly, some distribution utilities still use paper maps to keep records, track problems, and manage work crews. In contrast, electronic maps allow for easy updating, quick searches through large geographic areas, and clear communication with work crews. Electronic maps are only one example of the changes that upgrades in distribution software can bring. However, in an industry that prizes reliability and depends on tested operating procedures to maintain reliability, such fundamental changes come at the cost of extensive training programs and a period of heightened risk as personnel become accustomed to new practices.

The integration of new communications infrastructures, sensor technologies, and advanced information technology will enable new distribution system capabilities over the next several decades.

The time, money, and expertise required to implement a new DMS can vary greatly between utilities because a significant level of customization is necessary. A variety of equipment throughout the distribution system can be enabled to interact with DMSs. Many new sensors, protection equipment, and control devices have communication and computation capabilities. The number of sensors that a utility deploys and integrates with its DMS impacts the cost and time required for implementation and the usefulness of the resulting DMS. To upgrade its DMS from a software system developed in-house to a state-of-the-art vendor solution, one California utility attributed 40% of the estimated implementation cost to labor, IT, and equipment upgrades and 60% of the cost to software vendor services.[9]

Outage management systems (OMS) are another tool in the software suites that distribution system operators use. Sometimes viewed as a component of DMSs, OMSs typically use system models and graphical user interfaces to handle customer complaint calls, locate outages, and manage repair crews.[10] State-of-the-art OMSs can incorporate geographic information systems, electrical models, and real-time data from sensors to provide sophisticated, real-time visualization of the system during outages. Improved work-management software and real-time outage information with clearer communication between mobile units and control centers can increase the speed with which crews reach faults and the safety of their actions. A recent Lawrence Berkeley National Laboratory study quantifies the economic benefit of reducing outage time: using data from customer surveys, its authors conclude that the cost of an outage lasting one hour is approximately $4 for residential customers, $800 for small commercial and industrial customers, and $20,000 for medium and large commercial and industrial customers.[11] Of course, the actual costs of outages vary widely across different customers and regions, and computing average values requires a range of assumptions regarding outage and customer characteristics.

Integrating communications, IT infrastructure, and sensors with DMSs will enable a range of new distribution system operation applications. Two prominent examples are automated fault detection, isolation, and restoration (FDIR, also known as self-healing) and optimization of system voltages and power flows. The term "distribution automation" is often used to generically describe these applications of new technology to the maintenance, control, and operation of the distribution network. We address these new applications in the rest of this section.

FINDING

The use of new communication, sensor, and advanced information technologies can result in the integration and automation of many distribution system functions, yielding reduced costs and improved reliability.

Automated Fault Detection, Isolation, and Restoration

More extensive deployment of circuit breakers and communication devices combined with advanced control algorithms can enable automatic FDIR. As an example of FDIR in action, consider an automobile accident that knocks down a pole supporting distribution wires, interrupting service to customers. A distribution system with software for automatic FDIR in place that also includes multiple feeders and sectionalizing switches—switches that divide lines into independent sections—can isolate the site of the fault (the downed wires), perform analysis to determine the extent of damage and options for reconfiguration, and provide a secondary path for service to customers who would otherwise be without power.

This self-healing capability has the potential to improve reliability, enhance customer service, and reduce operation and management costs.[12] Deploying automated FDIR in legacy systems can speed these processes by removing the need for human action and decision-making. In distribution systems that already use automated FDIR processes, the addition of advanced control algorithms and more finely sectionalized distribution circuits in these systems can reduce the time of outages and the number of customers affected. For example, Oklahoma Gas & Electric Company reduced its outage time by between 54% and 70% on three circuits after installing hardware enabling FDIR capability.[13]

Oklahoma Gas & Electric Company reduced its outage time by between 54% and 70% on three circuits after installing hardware enabling FDIR capability.

To date, self-healing technology has been installed on only a small percentage of distribution feeders in the U.S.[14] Typically, the least reliable circuits in distribution systems are first to be upgraded because improving them will be of the most benefit to customers and the cost of deployment discourages system-wide upgrades. Many distribution utilities are now demonstrating this technology through projects partially funded by American Recovery and Reinvestment Act grants.[ii]

Voltage and Power Flow Optimization

As customers draw power from the distribution system, voltages decline along distribution lines. Without intervention, the voltage level at the end of a long distribution line will be lower than at the substation. With some exceptions, the size of the voltage drop increases when loads increase. To control voltage at the customer load point, utilities have long used adjustable transformers, known as "voltage regulators," and "capacitor banks"—a collection of capacitors that can be switched in and out of the circuit—to keep voltages within a specified range along the entire length of distribution lines. These devices are controlled from the distribution substation, which ensures that the voltage for each customer is between 95% and 105% of rated voltage.[15] For residential customers, where the rated voltage is 120 volts, this gives an acceptable range of 114–126 volts. Manufacturers design equipment, such as motors, to operate optimally within the range of ± 5% of nominal voltage. Supply voltage outside the acceptable range can result in inefficient operation and overheating, leading to reduced equipment life.

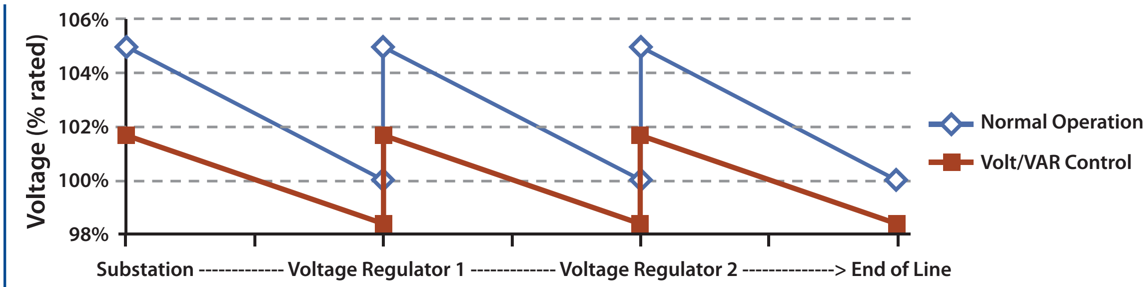
Operating at the upper end of the allowable voltage range is a common strategy because voltage is measured at the substation but not at the end of the line; to ensure the voltage at the end of the line is within limits, utilities often set the substation voltage at the upper end of the specification. Because load will draw more power with a higher voltage, tighter control of voltage can result in reduced power consumption.[iii] Tighter voltage limits and its benefits can be effected by a more sophisticated approach to voltage regulation called "volt/VAR control" which employs voltage sensors on the line, and particularly at its end, which feed back the measured voltages to the substation. Control equipment at the substation then adjusts the substation voltage and the voltage regulating equipment on the line to maintain the line voltage at the low end of its limits.

Figure 6.1 illustrates the potential effect of volt/VAR control on the voltage along a distribution feeder. In the figure, the vertical axis is voltage level and the horizontal axis, from left to right, represents the distance of a distribution line from the substation to the end of the line. The blue lines show the voltage distribution under normal operation, where voltage measurements are not fed back to the substation. The voltage variation along the line is seen to be 5%. The red lines represent the voltage distribution using volt/VAR control. The effect of sensing and feedback control is not only to

[ii] Track these projects at http://www.smartgrid.gov.

[iii] This relationship depends on the nature of the load. The correlation is very strong for resistive loads, such as incandescent lamps, but weak for many electronic devices with modern power supplies that compensate for voltage variations.

Figure 6.1 Voltage Profiles with and without Volt/Volt-Ampere Reactive (VAR) Control



reduce the average value of the voltage while maintaining it within its acceptable limits, but also to tighten its variation along the line to less than 4%.

Volt/VAR control also can be applied to reduce peak loads by decreasing feeder voltage to the lower end of the acceptable range. This approach, known as conservation voltage reduction (CVR), can yield a decrease in the total power drawn throughout the network, thereby deferring the need for capacity expansion and increasing efficiency. In a three-year study conducted for 13 utilities (30,000 customers) in the Pacific Northwest, maintaining the voltage between 114 and 120 volts at the customer level every other day yielded a 2% savings in annual energy delivered by substations.[16] Unlike brownouts or rolling blackouts, conservation voltage reduction does not necessarily negatively impact the quality of service that utilities provide to their customers.

Many utilities are currently planning to introduce volt/VAR control and CVR programs in their territory. Oklahoma Gas & Electric Company calculated that installing volt/VAR control on 400 of their highest-priority circuits would save 106 gigawatt hours per year, or approximately 0.4% of their annual energy sales, and defer 80 megawatts of future generation on their existing capacity of 6,800 megawatts.[17] Southern California Edison is deploying a CVR program that uses voltage data from their advanced metering infrastructure and is estimated to save their customers between 1% and 4% of energy consumption without any behavior changes.[18]

FINDING

The use of Volt/VAR control can result in more efficient use of the distribution network and the possibility of introducing conservation voltage reduction (CVR) programs.

As discussed in Chapter 8, the practice of utilities recovering a substantial portion of their distribution and transmission costs through volumetric charges, as is currently the dominant practice in the U.S., gives utilities incentives to increase their sales and discourage energy conservation. This incentive misalignment could slow the introduction of CVR programs that promise reduced energy consumption.

6.2 ADVANCED METERING FOR THE DISTRIBUTION SYSTEM

New customer-metering investments also can enhance the performance of distribution systems. Utilities traditionally have used meters strictly for billing purposes. In this traditional paradigm, utility employees visit customer premises and manually read electromechanical watt-hour meters that measure electric energy consumption. These meters are no longer commercially available in the U.S., having been replaced by solid-state electronic meters, though many electromechanical meters are still in use today.[19] Electronic meters can more easily store and communicate energy consumption as a function of time. These new meters have enabled two distinct new approaches to data capture and management: automated meter reading (AMR) systems and advanced metering infrastructure (AMI) systems.[20]

AMR technology allows utilities to read customer meters via short-range radio-frequency signals. These systems typically capture meter readings from the street using specially equipped vehicles. They can reduce meter-reading costs by eliminating the need for employees to manually read meters. Many utilities throughout the U.S. have deployed AMR systems over recent decades, with more than 47 million AMR meters reported in operation as of 2009, roughly one-third of the 144 million total U.S. residential, commercial, and industrial meters.[21]

AMI systems—also known as smart meters—combine meters with two-way communication capabilities. These systems typically are capable of recording near-real-time data on power consumption and reporting that consumption to the utility at frequencies of an hour or less.[22] Utilities also can typically communicate with AMI meters—for example, to check customer connection status or connect or disconnect service remotely. AMI systems also can allow utilities to communicate directly with loads through the meter, as discussed in Chapter 7. In contrast to AMR systems, AMI installations in the U.S. are still in their infancy but are growing rapidly. Penetration estimates vary across the industry. In 2009, data submitted by the industry to the U.S. Energy Information Administration indicated that 9.6 million customer meters in the U.S. were AMI devices.[23] The Federal Energy Regulatory Commission's 2010 advanced metering survey reported penetration of more than 12 million smart meters by the end of 2009.[24] The difference likely reflects not just growth but also differences in data sources. The federal government has subsidized additional deployment of AMI systems in a number of utilities through the Recovery Act, supporting approximately 30 large deployments throughout the U.S.[25] An estimated 20 million AMI meters have been deployed nationwide as of June 2011.[26]

The benefits of advanced metering vary with every utility, but generally it reduces the costs of meter reading, improves customer support, and enhances distribution monitoring and management.

The benefits of advanced metering vary with every utility, but generally it reduces the costs of meter reading, improves customer support, and enhances distribution monitoring and management. For example, AMI meters equipped with remote service switches allow utilities to remotely connect or disconnect service when customers move in or out. This can reduce the time and cost of connections, eliminate usage that occurs after customers have closed their accounts, and may reduce uncollected bills. Some utility AMI rate filings indicate that enhanced detection of theft or diversion—that is, electricity use that bypasses a meter—may increase revenues. Of great import, however, is the role AMI, and particularly its two-way communication capability, can play in facilitating dynamic pricing for residential customers, as discussed in Chapter 7.

In regulatory filings, utilities mainly have focused on quantifying the following operational benefits of AMI:

- **Metering:** Installation of AMI means that meter reading can be fully automated. This reduces labor cost and the costs of owning and maintaining meter-reading vehicles.

- **Billing:** Billing can be more accurate and timely, improving utilities' cash flows.

- **Customer Support:** Service can be switched on or off remotely, increasing accounting accuracy, reducing customer debts, and reducing the number of times utility personnel must visit customer locations. In addition, call centers can more effectively help customers because of readily available and accurate metering data, thereby reducing the average duration of customer support calls.

- **Grid Management:** The data from interval metering (meters that can be read at intervals of an hour or less) can be used to more effectively manage distribution system assets; for example, precise metering can alert distribution operators to an overloaded distribution transformer.

While the operational benefits of installing AMI can be substantial, they may not cover the full cost of the up-front infrastructure investment.

While the operational benefits of installing AMI can be substantial, they may not cover the full cost of the up-front infrastructure investment. Table 6.1 presents expected costs and benefits for a sample of AMI projects around the country, collected by a search of regulatory filings. The expected all-in costs of AMI deployments over the past five years averaged between $150 and $400 per meter across these projects, with much of the variation due to differences across systems in customer mix and density, labor costs, and prior meter investments. Recent discussions of AMI costs and benefits frequently use a lower range of expected costs, $150–$250 per meter, though it is not clear how these estimates relate to data on actual deployments.[27] For systems with dispersed customers, traditional electromechanical meters near the end of their expected useful lives, and combined electricity and gas businesses that can share much of the AMI infrastructure and overhead, operational savings may cover a high fraction of AMI deployment costs. Where operational benefits roughly offset the investment costs, there may be little or no impact on electricity rates, and a decision to deploy AMI is relatively straightforward. At the other extreme, utilities with relatively new AMR meters throughout their system have already realized much of the meter-reading cost reductions, the largest single category of operational benefits of AMI, and may be adding little to the useful lives of their meter system through early replacement. For systems in this situation, operational savings may offset half or less of the projected incremental cost of AMI deployment. In the most extreme case illustrated in Table 6.1, operational savings cover only 15% of AMI costs.

In some cases, these benefit–cost ratios may be conservative. AMI investments that can be funded entirely out of operational savings may not generate a rate filing and, therefore, do not appear in our table. In rate filings, concerns have been expressed that utilities fear overestimating savings that do not later materialize or incurring costs above those approved in initial rate filings, particularly if the regulator assigns most of the risk to shareholders, as some have recently done. These concerns may bias reported benefit–cost ratios below expected levels.

Operational savings are also not the only benefit of AMI. Advocates of AMI argue that the nonoperational benefits from AMI-enabled demand response and energy conservation dwarf the operational savings.[28] Their importance to an AMI investment case depends on what fraction of costs are offset by operational savings, whether utilities and regulators are willing to commit to pricing reforms, and how customers within a particular service area are likely to respond. Table 6.1 includes several estimates of these

Table 6.1 Operational Benefit–Cost Ratio of Different Advanced Metering Projects

Utility (State)	Year	Meters (Millions)	Average Cost/Meter Installed ($/meter)	Operational Benefits/Meter Installed ($/meter)	Operational Benefits/Cost Ratio	Nonoperational Benefits/Meter Installed ($/meter)	Total Benefits/ Cost Ratio	Reference
CenterPoint (TX)	2008	2.4	$332	$50	0.15	—	—	CenterPoint Energy Houston Electric, "Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System," Texas PUC Docket No. 35639, Document No. 203.
Delmarva (MD)	2010	0.22	$363	$183	0.50	$252	1.20	Delmarva Power & Light Company, "Advanced Metering Infrastructure Business Case and Associated Benefits to Costs Analysis for Maryland in Compliance with Order No. 83571," Maryland Public Service Commission Case No. 9207, Document No. 102, submitted 12/14/2010.
Southern California Edison (CA)	2007	5.3	$374	$217	0.58	$159	1.00	California Public Utility Commission, "Decision Approving Settlement on Southern California Edison Company Advanced Metering Infrastructure Deployment," Case No. A.07-07-026, 7/31/2007.
Connecticut Light & Power (CT)	2010	1.2	$377–$484	$94–$232	0.19–0.62	$63–$804	0.33–2.75	Connecticut Light & Power, "CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis," Connecticut Department of Public Utility Control, Docket No. 05-10-03RE01, submitted 3/31/2010.
Portland General Electric (OR)	2007	0.843	$157	$197	1.26	$4–$55	1.28–1.61	B. Carpenter and A. Tooman, Portland Generation Electric Company, "Costs and Benefits," Oregon Public Utility Commission, Docket No. UE 189, submitted 7/27/2007.
Baltimore Gas & Electric (MD)*	2009	2.09	$253	$128	0.50	$478	2.40	Baltimore Gas & Electric Company, "The Smart Grid Initiative Business Case Advanced Metering and Smart Energy Pricing Program" Maryland Public Service Commission, Case No. 9208, submitted 07/13/2009.
NY State Electric & Gas (NY)*	2007	1.13	$322	$185	0.58	—	—	Rochester Gas & Electric Corporation and New York State Electric & Gas Company, "Advanced Metering Infrastructure Overview and Plan," New York State Public Service Commission Case No. 00-E-0165, submitted 02/1/2007.

Table 6.1 Operational Benefit–Cost Ratio of Different Advanced Metering Projects *continued*

Utility (State)	Year	Meters (Millions)	Average Cost/Meter Installed ($/meter)	Operational Benefits/Meter Installed ($/meter)	Operational Benefits/Cost Ratio	Nonoperational Benefits/Meter Installed ($/meter)	Total Benefits/ Cost Ratio	Reference
Rochester Gas & Electric (NY)*	2007	0.67	$250	$150	0.60	—	—	Rochester Gas & Electric Corporation and New York State Electric & Gas Company, "Advanced Metering Infrastructure Overview and Plan," New York State Public Service Commission Case No. 00-E-0165, submitted 02/1/2007.
Consolidated Edison (NY)*	2007	4.8	$149	$109	0.73	$55	1.10	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., "Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure by Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.," New York State Public Service Commission Case No. 00-E-0165, submitted 3/28/2007.
Pacific Gas & Electric (CA)*	2006	9.3	$243	$218	0.90	$36	1.05	California Public Utility Commission, "Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure," Decision 06-07-027, July 20, 2006.

*These projects include upgrades to natural gas metering systems in addition to electricity metering upgrades. The number of meters for these projects corresponds to both electricity and gas meters.

Note: The data in Table 6.1 has been extracted from state regulatory proceedings. Prospective calculations of AMI benefits and costs require a range of assumptions (e.g., project lifetimes, depreciation schedules). Also, as described in the text, these results are subject to significant uncertainty (e.g., technology costs, deployment schedules, dynamic pricing adoption rates, etc.). The cost of AMI projects also depend on the characteristics of each utility's service territory and the nature of their existing technology and business processes related to customer metering.

nonoperational benefits of AMI investments. Unfortunately, these are much more difficult to estimate with precision. Chapter 7 addresses these issues in detail.

Most utility regulatory filings also omit reliability gains from benefit–cost calculations. AMI can allow some utilities to respond more rapidly to distribution outages and reduce average outage restoration times for customers. Although the frequency or scale of distribution outages cannot be lowered by using advanced metering systems alone, AMI can enable utilities to quickly and automatically pinpoint where an outage has occurred and respond more rapidly with service vehicles, reducing the average outage time experienced by customers.

In addition, identifying "false alarms"—outage reports called in when electricity is in fact flowing to the meter—may reduce costs by avoiding unnecessary dispatch of crews, although malicious hacking of AMI data could create such alarms (see Chapter 9 for further discussion of so-called "cyberattacks").

In the one filing that does incorporate this benefit, Connecticut Light & Power estimates a reduction in average yearly outage duration of six minutes per customer, mainly attributed to "increased notification accuracy that AMI provides during storms." In a base-case scenario, the utility estimates that the expected reduction in outage minutes alone would account for $59 million in benefits over the lifetime of a $493 million AMI investment program, using reasonable estimates of outage costs from a survey of outage-cost studies.[29]

FINDING

The ratio of operational benefits to total cost for AMI projects varies widely across different utilities. Where operational benefits are low, nonoperational benefits, such as those associated with demand response programs, are a significant factor in determining whether AMI installations are cost-effective.

For systems that have begun deploying AMI, customers' concerns about health and privacy impacts can pose important challenges. Early and effective engagement with customers appears critical to surmounting these concerns.

While the scientific literature does not suggest that radio waves from smart meters have adverse health effects, debate over these risks can be so intense that utilities must retool AMI programs in response.[30] Citing customer concerns, the Maine Public Utility Commission recently approved a meter surcharge program that would allow customers to opt out of smart meter installation or turn off the wireless transmitting function, and Pacific Gas & Electric has proposed a similar program for its territory.[31]

Privacy issues surrounding AMI arise from the fact that smart meters measure and record customer's power usage at frequent intervals. The power usage profiles thus accumulated could be used to infer, for example, when a customer is away on vacation. The National Institute of Standards and Technology and several state public utility commissions are actively addressing these privacy concerns, which have gained international attention. We discuss the intricacies of this issue in Chapter 9.

6.3 PILOT PROGRAMS AND DEPLOYMENT CHALLENGES

The Recovery Act provided about $4.5 billion for the electric grid, and many utilities have used this funding for advanced distribution system technology projects. The bulk of this funding is being distributed through two U.S. Department of Energy programs: Smart Grid Demonstration Projects (SGDP) and Smart Grid Investment Grants (SGIG). The goal of SGDP is "to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today." The SGIG program aims "to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and techniques that increase flexibility, functionality, interoperability, cybersecurity, situational awareness, and operational efficiency."[32] Each funding opportunity required recipients to provide one-to-one matching funds. Ninety-nine SGIG recipients have been awarded a total of $3.4 billion and 32 SGDP recipients have been awarded a total of about $600 million.

Many award recipients are using the funding to accelerate distribution modernization efforts. For example, NSTAR has been installing hardware required to sectionalize circuits since 2003; prior to the SGIG award in 2009, 1,200 sectionalizing switches already had been installed. Using SGIG funding, NSTAR will upgrade from an FDIR system requiring human action to one that is completely automated; roughly 70% of circuits will have self-healing (automated FDIR) capabilities by the end of 2013, and the utility expects that 50% fewer customers will experience outages as a result.[33] Similarly, PPL Electric Utilities has been installing hardware allowing remote control of their distribution system since 2003 and is now using SGIG funding to install DMS software, a dedicated communication system, and new hardware enabling full automation of about 50 circuits. With modern DMS software and a communications network in place, further hardware upgrades enabling full automation of other PPL circuits are expected in future investments.[34]

The projects funded by SGIG and SGDP programs may prove a beneficial step toward distribution system modernization. However, the value of these and future advanced distribution technology deployments and pilot projects will depend on effective information sharing, the development of interoperability standards, and efforts to properly align regulatory incentives with system modernization goals.

Currently, detailed information on federally funded smart grid projects, expected benefits, utility characteristics, progress, and lessons learned is sparse and insufficient to apply to other similar projects. Although industry can share information at several newly launched websites—including www.sgiclearinghouse.org, www.smartgrid.gov, and www.recovery.gov—very little of this information pertains to ongoing distribution modernization efforts. Getting detailed information has been difficult, despite efforts to individually contact funding recipients and collect detailed information on expected costs and benefits for a majority of proposed projects.

The White House Office of Science and Technology Policy has drafted a framework for the future grid that emphasizes the importance of information sharing.[35] A mechanism for sharing the results of publicly funded research, development, and demonstration projects is essential to ensure that the funding provided to one utility will benefit other utilities as well. Transparency to the public is important not only to ensure accountability but also to facilitate further research that may help guide future investments. However, utilities may be appropriately unwilling to publicly share certain information due to concerns about security and the sensitive nature of some business information. Therefore, distribution utilities with common interests in advanced technologies may need to use direct channels for cooperation and communication. Indeed, industry stakeholders with whom we have spoken in the course of our research have indicated that a mix of informal and formal mechanisms for inter-utility collaboration exist in the U.S. today. Sometimes these activities are coordinated via such institutions as the Electric Power Research Institute and industry trade associations including the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association.

FINDING

Information sharing among Smart Grid Investment Grant and Smart Grid Demonstration Project funding recipients and other utilities is essential to capture the value of these projects.

Interoperability of IT equipment, software, and communications technologies from various vendors remains an important challenge. The National Institute of Standards and Technology has undertaken work to coordinate standards for the future grid that will address these interoperability issues. We address these standards and other interoperability concerns in Chapter 9.

We noted in Chapter 1 a general decrease in budgets for utility research and development activities, which may hamper innovative activity. Further, deploying new technologies frequently involves uncertainty about the economics and performance of those innovations. Conventional rate of return regulation with *ex post* prudency reviews of capital investments may discourage or delay investments that are perceived to involve greater risks.[36] Regulators in many states may have cause to be similarly risk-averse toward significant new investments. This problem is addressed in greater depth in Chapter 8.

6.4 CONCLUSIONS AND RECOMMENDATION

Substantial changes to distribution system operation will occur between now and 2030. In large part, the changes discussed in this chapter are a necessary response to the new challenges that electric vehicles and distributed generation pose. Modern distribution management systems and other control center software are necessary to unlock the benefits from increased deployments of sensors and control hardware. Automated FDIR and volt/VAR control are technologies that require modern hardware and software but offer significant benefits in return. To the extent that these technologies facilitate aspects of performance that have not been the focus of traditional distribution system investments and involve greater uncertainty in their payoff, utility regulators and supervisors may need new approaches to encourage innovation. We discuss this at greater length in Chapter 8.

AMI systems offer clear operational savings, and many utilities already have committed to or executed broad deployment of this technology. For those that have not, particularly those with existing AMR systems, operational benefits alone may not be sufficient to justify the cost of a broad AMI rollout. Quantifying the likely magnitude of benefits from AMI-enabled demand response, energy efficiency programs, and increased reliability will be critical to assessing the business case for AMI investments for these utilities. We address these in detail in Chapter 7. We describe the privacy and cybersecurity concerns associated with this technology in Chapter 9.

Technology demonstrations and pilot projects are an important step toward implementing cost-effective advanced distribution technologies. Federal stimulus funding is currently supporting many such projects. Comprehensive inter-utility information sharing will be crucial to realizing the full potential of these public investments. Regulators only recently have introduced websites intended to facilitate information sharing about these projects, and the sites currently have little useful data related to ongoing projects. As these projects progress, these websites may yet facilitate industry learning. However, direct utility-to-utility communications and collaboration should also be encouraged to ensure that sufficiently detailed lessons learned from demonstration projects are available to inform future investment decisions. It is critical that utilities share details on both successes and failures.

RECOMMENDATION

Achieving the full potential of federal funding for distribution system technology demonstration projects will require that data on those projects (both successes and failures) are shared widely. Several websites, including www.smartgrid.gov and www.sgiclearinghouse.org, have been established to disseminate information about these projects. As results become available, policy makers should work to ensure that resources such as these are effectively used to share detailed and comprehensive data and lessons learned.

To assure continuation of the modernization process initiated by the Recovery Act grants, state regulators and other supervisors of distribution utilities must be willing to approve investments that have a greater degree of risk than has been customary for distribution systems, as we discuss at length in Chapter 8.

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Chapter 7: Engaging Electricity Demand

> In this chapter, we discuss the opportunities for grid operation associated with more actively engaging electricity demand. The past several years have seen significant and growing interest in encouraging greater customer involvement in managing their electricity use. Technologies that facilitate increased demand response and enhance energy efficiency are likely to become more affordable as they mature and costs continue to fall.
>
> Sections 7.1 through 7.4 provide background. Section 7.1 introduces the motivation for increasing demand engagement, while Section 7.2 describes demand response programs as they exist today. Section 7.3 then assesses the potential benefits of more active demand management by electricity customers, and assesses the substantial uncertainty that continues to surround estimates of potential demand response benefits, particularly at the residential level. Section 7.4 describes energy conservation and energy-efficiency programs and their relationship to demand response programs.
>
> Section 7.5 provides our main findings related to demand engagement. Carefully designed customer engagement programs and transition policies to dynamic pricing tariffs will be critical to creating responsive demand and realizing the full potential of advanced metering infrastructure (AMI) investments. Complementary technologies that promise to automate customer responses are likely to be important in these objectives. Their relative immaturity in 2011 signals the importance of ensuring upward compatibility and interoperability, to avoid stranding customer investments. Finally, we note that results of ongoing pilots and system deployments could dramatically narrow uncertainty surrounding the costs and benefits of AMI, associated technologies, and dynamic pricing—if data are shared.
>
> Section 7.6 details our recommendations. We first recommend that utilities that have already committed to AMI deployment prioritize transition paths to broad-based dynamic pricing. We highlight the importance of publicly sharing information on their customer engagement programs, investment costs, and results of demand response initiatives. Such data can improve program design for adopters and decision quality for utilities that must evaluate whether to accelerate replacement of their customers' meters. We recommend that decision makers for utilities confronting uncertain investment cases recognize the option value of deferring decisions pending that early deployment data: adoption decisions are not "now or never" but "now or re-evaluate with new data."

INTRODUCTION

Policy makers, regulators, grid system operators, utilities, and customer groups have expressed increasing interest in electricity load becoming more responsive to system conditions, particularly to variations in the cost of supplying energy. More responsive demand can improve system efficiency and reduce costs. Reduced consumption at or near system peaks can reduce the need for expensive investment in additional generating capacity, and shifting consumption to off-peak periods can flatten load curves, improve capacity utilization on the system, and reduce the total cost of delivering a given quantity of energy. Real-time adjustments to demand could reduce the cost of managing

More responsive demand can improve system efficiency and reduce costs.

supply volatility brought on by increased penetration of variable energy resources (VERs) and, by promoting off-peak charging, could reduce the need for new generation and network capacity to accommodate electric vehicles and plug-in hybrid vehicles. More price-responsive demand may help to mitigate market power concerns in restructured wholesale generation markets by reducing the profitability of price increases. In addition, making their own real-time electricity usage more visible to consumers may complement energy conservation goals.

The growing interest in engaging electricity demand has been accompanied by significant advances in the development and diffusion of technologies capable of facilitating this change. As described in Chapter 6, the U.S. has seen dramatic growth in the deployment of advanced metering infrastructure (AMI), which records a customer's electricity consumption at least hourly and provides two-way communication with the distribution utility. In addition to providing more granular data on customer usage, AMI complements a range of "smart" energy response and management technologies—such as programmable controllable thermostats and "smart charging" of electric vehicles—that can, in principle, involve even smaller commercial and residential customers in more active management of their electricity consumption and facilitate their responses to price or other supply-side signals.

Historically, only the demands of those large customers who had agreed to take "interruptible" power in exchange for lower rates were responsive to system conditions, and then only in emergencies or when demand nears system capacity. New technologies make it easier to reduce the demands of even smaller customers in emergency conditions. But the potential benefits of demand response go well beyond dealing with emergencies, as suggested above. To capture these potential benefits, however, communication to customers must convey more than simple signals of emergency conditions, and customers must respond appropriately to those communications.

As we look to 2030 and beyond, it is difficult to envision a scenario without broad deployment of some form of advanced metering across U.S. utilities.

AMI permits fine-grained communication of system conditions to customers and fine-grained measurement of customer responses. As we look to 2030 and beyond, it is difficult to envision a scenario without broad deployment of some form of advanced metering across U.S. utilities. Most currently installed meters will have reached the end of their useful lives by 2030, and some form of AMI is almost certain to be the replacement technology of choice. But utility systems may choose to invest in "early" AMI deployment, even before their current meters have fully depreciated. Some operate in states that have made universal AMI deployment a key policy objective. For others, as described in Chapter 6, system-wide deployment of AMI may reduce operating costs and, as part of a broader distribution system modernization and automation program, enhance service quality. However, as noted in Chapter 6, these operational benefits of AMI frequently constitute only a fraction—for some utilities, particularly those that have installed automated meter reading systems, a relatively small fraction—of the estimated capital costs of its universal deployment. For potential early adopters, the economic case for AMI may, therefore, rest heavily on the magnitude of benefits it creates through greater demand-side participation in electricity markets. AMI's ability to facilitate demand response through dynamic pricing—tariffs that go beyond simple time-of-use prices by allowing prices to change in response to contemporaneous system conditions—holds particular promise.

The cost-effectiveness of dynamic pricing already has been demonstrated for large-scale industrial and commercial customers.

The cost-effectiveness of dynamic pricing already has been demonstrated for large-scale industrial and commercial customers, even with their greater metering cost.[1] The focus of recent research therefore has been on residential and smaller commercial customers. Pilot projects demonstrate that experimental populations of residential customers reduce consumption when electricity prices are high.[2] Yet regulatory commitments to tap the capabilities of these meters for dynamic pricing by smaller commercial and residential customers often lag their installation. This appears to be due in part to continuing debate over how responsive the *typical* smaller consumer is likely to be to signals of electricity costs, particularly

Electricity on average accounts for only 2% to 3% of household expenditures.

since electricity on average accounts for only 2% to 3% of household expenditures.[3] It also reflects concerns about customer reactions to AMI technology, volatile electric bills (particularly unexpectedly high bills), and the differential impact of dynamic pricing on low-income customers. This chapter discusses the nature and impact of current demand response programs and assesses the evidence on the potential for expanded demand engagement, particularly by residential customers.

The discussion highlights an important question for regulators and utilities: what are the trade-offs between rapid universal rollout of AMI technology and a staged deployment that evaluates the experience of early adopters before embarking on later waves of installations? The diffusion of AMI meters has been growing rapidly, assisted by legislative directives in some states, including California, Pennsylvania, and Texas, and smart grid stimulus grants under the American Recovery and Reinvestment Act of 2009 that have committed utilities to system-wide installation of AMI infrastructure. An estimated 27 million AMI meters have been deployed nationwide as of September 2011, and some projections suggest installations could reach more than 60 million (40% of utility customers) by 2015.[i] Information from these projects, if broadly shared, can help refine the wide range of estimated potential benefits of AMI-facilitated demand engagement, inform "all-in" cost estimates for system-wide adoption, and highlight both technical and human-factor challenges in rolling out these technologies. Utilities and public utility commissions that have not yet committed to near-term AMI deployment can use this information to decide when and how to make cost-effective use of advanced meters.

7.1 WHY ENGAGE DEMAND?

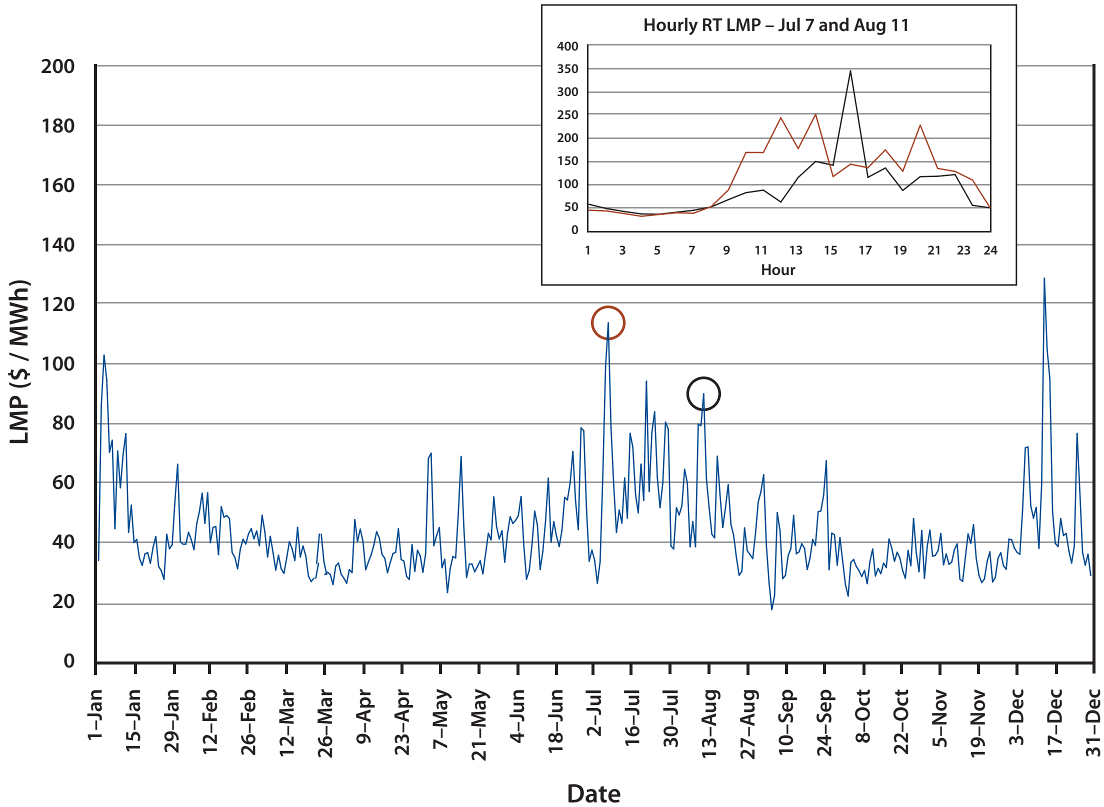
As we have discussed in earlier chapters, electricity systems must precisely balance supply and demand at each moment in time. System operators historically have ensured the equality of supply and demand largely through supply-side tools: operators adjust the dispatch schedule for generators to meet forecast demand, adjust dispatch as forecasts are updated, and use ancillary services to adjust to real-time deviations in demand from forecast. Predictable variation in demand over time, day, and season is associated with changes in the marginal cost of supplying electricity that regularly vary by a factor of two or three.

[i] The 2015 projections may be aggressive given that AMI deployments frequently have been delayed or deferred.[4]

More important, unanticipated changes in generator or transmission availability, or unusually high demand—for example, air conditioning loads on an exceptionally hot August afternoon—may cause the marginal cost of providing an additional megawatt hour (MWh) of electricity to consumers to increase fivefold or tenfold or more. Compare, for instance, the PJM Interconnection region 2010 average daily real-time wholesale prices shown in Figure 7.1 with the hourly prices (inset) for two summer 2010 days.

Despite these cost fluctuations, the majority of electricity customers in the U.S., including almost all smaller commercial and residential customers, face retail prices that do not change over the course of a day or a week. Some face prices that may not vary even seasonally. As a result, these customers have no incentive to shift their electricity use away from high system demand hours, and consumption can be highly "peaked." It is estimated that fewer than 1% of annual hours (60–100 of 8,760 hours) account for 10%–18% of the capacity needs in North America.[5] And, as Chapter 1 has shown, the "peakedness" of demand—measured, say, by the ratio of peak demand to average demand over a year—generally has been increasing over time. This problem affects generating capacity as well as electricity transmission and distribution networks because all must be sized to meet predicted maximum demand (plus a safety margin) at all times and across all geographical locations.

Figure 7.1 2010 Average Daily versus Selected Hourly Average Real-Time Locational Marginal Price (RT LMP) in the PJM Interconnection



Data Source: PJM, "Monthly Locational Marginal Pricing," http://pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx.

Demand response programs may reduce the total cost of maintaining system balance by inducing changes in consumption, particularly when system capacity utilization, and thus the opportunity cost of energy, is high. The Federal Energy Regulatory Commission (FERC) uses this definition of demand response: "Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[6]

As the FERC definition suggests, these programs generally rely on one of two very different mechanisms. "Load management or control" programs offer customers incentives to reduce their consumption below a baseline or expected level in response to an instruction or signal from the system operator, or to install a switch that gives the operator or a third-party aggregator direct control of a customer's load. Alternatively, "price-responsive demand" results when customers face prices that vary with system supply conditions and decide to reduce or to shift consumption when they value electricity at less than the observed current-period price (or to increase consumption during low-price periods, or to do both).

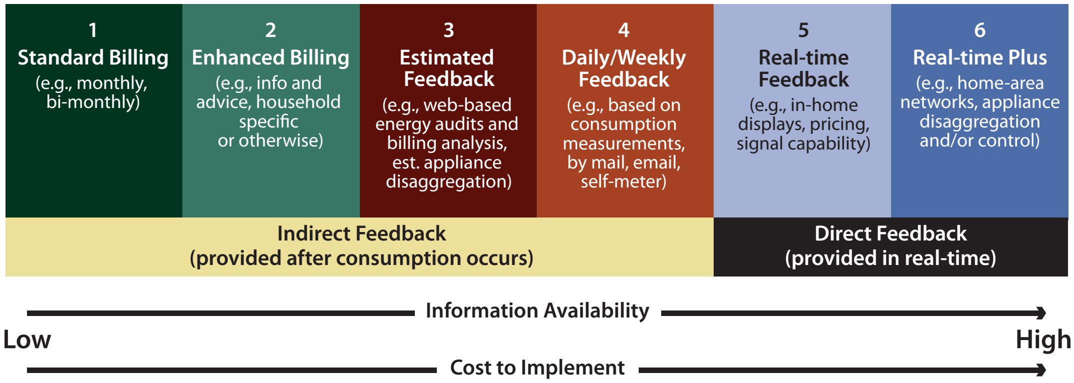
In practice, customer load response may differ substantially within and across these mechanisms. It may be useful going forward to distinguish between dispatchable programs, in which system operators, utilities, or third-party aggregators directly control load responses, versus reactive programs, based on customers' voluntary reactions to price or other signals. These need not be mutually exclusive at the level of the utility or competitive retail supplier of energy: dynamic pricing may both enhance the attractiveness of dispatchable load programs and encourage consumers to respond (either manually or automatically) to price or other signals they receive.

A second reason often given to engage energy demand is to reduce energy consumption. Demand responsiveness is distinct from energy efficiency or conservation, however, and though they may be related, one does not imply the other.[7] Demand response programs generally focus on reducing consumption at particular times, often shifting it to other times, while efficiency and conservation programs target reductions in overall electricity consumption. Some conservation may occur through demand response, as when usage at peak periods is eliminated rather than shifted: consider the effect of turning up an air conditioner thermostat or turning off lights during a summer weekday afternoon.[8] But some peak use, such as clothes drying, may simply be rescheduled, and lower off-peak prices associated with many dynamic pricing structures may further increase off-peak usage. Whether the direct net effect of demand response is to reduce or increase overall consumption is ultimately an empirical question, and there is considerable uncertainty in estimates of the likely net impact.

Demand responsiveness is distinct from energy efficiency or conservation, however, and though they may be related, one does not imply the other.

The detail and immediacy of energy consumption data from AMI meters, however, may provide additional support to conservation goals. For example, granular consumption data may offer insight into opportunities to tune building energy use and reduce consumption. A variety of third-party providers currently offer services to optimize building energy use based on detailed energy usage data, and this market seems likely to see substantial growth

Figure 7.2 Informational Feedback Continuum



Source: Electric Power Research Institute, *Residential Electricity Use Feedback: A Research Synthesis and Economic Framework* (Palo Alto, CA, 2009).

as AMI deployment expands.[ii] In residential applications, research increasingly focuses on the use of behavioral interventions through feedback mechanisms to reduce electricity consumption. These mechanisms provide information

U.S. demand response programs have grown substantially in recent years.

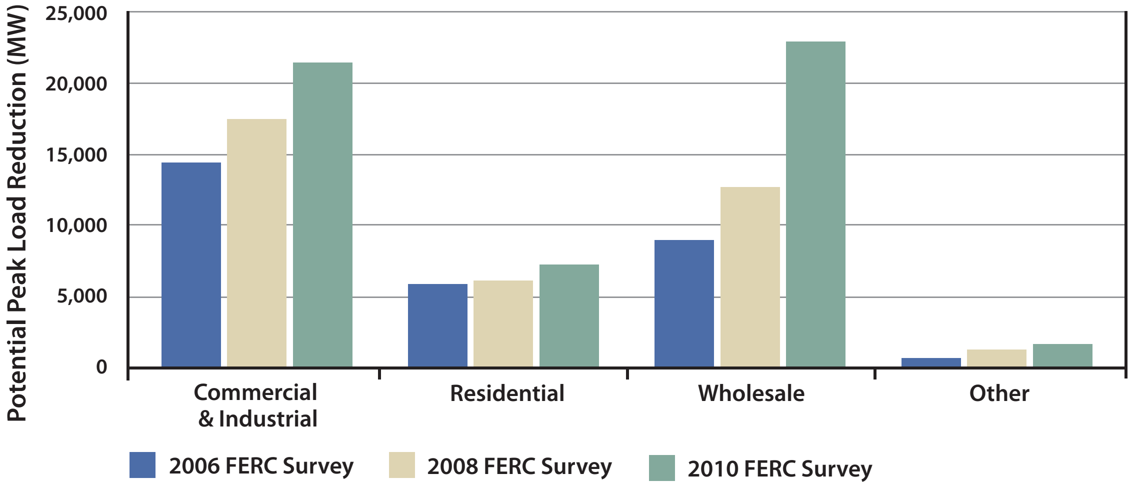
and assessment of behavior, often in the context of positive social norms, such as energy conservation. They might, for example, analyze the impact of reporting a consumer's electricity usage in comparison to that of neighbors.[9] In the residential electricity sector, this may involve either direct real-time information on consumption or indirect feedback provided at some later time, forming a continuum, as illustrated in Figure 7.2. AMI would be an integral part of the systems of direct real-time feedback at the upper end of the continuum, but could also contribute more granular information to indirect feedback mechanisms.[10]

7.2 DEMAND RESPONSE PROGRAMS TODAY

U.S. demand response programs have grown substantially in recent years. FERC reports enrollment in demand response programs collected in its 2006, 2008, and 2010 biennial surveys (released in 2007, 2009, and 2011, and reporting data for the full year prior to the survey date). By the 2010 survey, FERC recorded 53 gigawatts of potential peak load enrolled across a wide range of demand response programs, reflecting an 80% increase since the 2006 survey.[11] Commercial and industrial customers, who account for roughly 60% of U.S. electricity consumption, have historically accounted for the bulk of load enrolled in demand response programs, primarily through various load management programs. More recently, programs that allow customers or third-party aggregators to bid demand response into wholesale markets have increased dramatically and now comprise the largest category of demand response by enrolled load, as shown in Figure 7.3.

[ii] Southern California Edison recently entered a contract with the energy management company EnerNOC, for example, to support AMI-enabled commercial and institutional customer access to "EfficiencySMART Commissioning" software. The utility promises participating sites "10% or more savings on their total addressable energy expenditures."[12]

Figure 7.3 Reported U.S. Potential Peak Load Reduction by Customer Class in 2006, 2008, and 2010 Federal Energy Regulatory Commission (FERC) Surveys (megawatts)



Source: Federal Energy Regulatory Commission, 2006 Assessment of Demand Response and Advanced Metering Staff Report (Washington, DC, 2006); Federal Energy Regulatory Commission, 2008 Assessment of Demand Response and Advanced Metering Staff Report (Washington, DC, 2008); Federal Energy Regulatory Commission, 2010 Assessment of Demand Response and Advanced Metering Staff Report (Washington, DC, 2011).

Measuring demand response potential is challenging.

Measuring demand response potential is challenging. FERC's "potential peak load reduction" is a better indicator of aggregate load enrolled in a demand response program than of expected reductions in system demand at peak periods. Nevertheless, it currently provides the greatest comparability over time and across systems.[iii] There is some promise of progress on this front. The North American Electric Reliability Council (NERC) is developing a Demand Response Availability Data System to codify reporting of demand response enrollment and collect information on their actual responses to system "events" in an effort to improve data accuracy and predictability of demand response resources.[13] At present, NERC is focused in Phases I and II only on dispatchable, controllable resources that system operators can direct to respond to reliability-driven events. In Phases III and IV, this will be extended to nondispatchable, reactive (defined to include price-mediated) demand response resources. NERC's goal is to develop performance-based data that will enhance industry confidence in the measurement and use of demand response resources to meet one or more core objectives.

[iii] Enrolled "potential peak load reduction" as measured by the FERC survey does not necessarily translate to actual, expected, or available load reduction at any given time for a number of reasons. For example, customers may not be drawing their full enrolled load at the time of a demand response event; local transmission congestion may render demand response from customers in uncongested areas irrelevant; or restrictions in the program may explicitly or implicitly limit the frequency or duration of system operator calls on a given customer to reduce their load. Finally, voluntary demand response programs typically provide less predictable and lower overall responses per MW of enrolled load than do direct load control or mandatory response programs.[14] FERC reports that aggregate actual demand response averages less than one-third of potential peak reduction, with substantial variation in that figure across regions and years.[15]

Demand response programs may be targeted at various objectives. The earliest and most common focus has been reliability. Programs with this aim elicit customer reductions, usually through load management, in response to system emergencies or periods when electricity demand threatens to exceed the available supply of generation or network capacity.

More recent programs have begun to focus on reducing consumption in non-crisis peak periods and smoothing demand over time.

More recent programs have begun to focus on reducing consumption in non-crisis peak periods and smoothing demand over time. As noted in Chapter 1, in the capital-intensive electricity industry with no inventory and limited storage capability, generation, transmission, and distribution capacity that is sized to meet the maximum expected demand may go underutilized or unused in most periods, raising the long-run average cost of supplying a given amount of energy. Solutions to this "peak load" problem focus on economic incentives, price policies, and regulations that allow for an efficient investment in and use of capacity. While these may complement reliability objectives, their focus tends to be on long-run efficiencies rather than short-run operational exigencies. The greatest growth in programs targeted at peak load management has been in regions that allow demand-side resources to participate in long-term wholesale capacity markets.

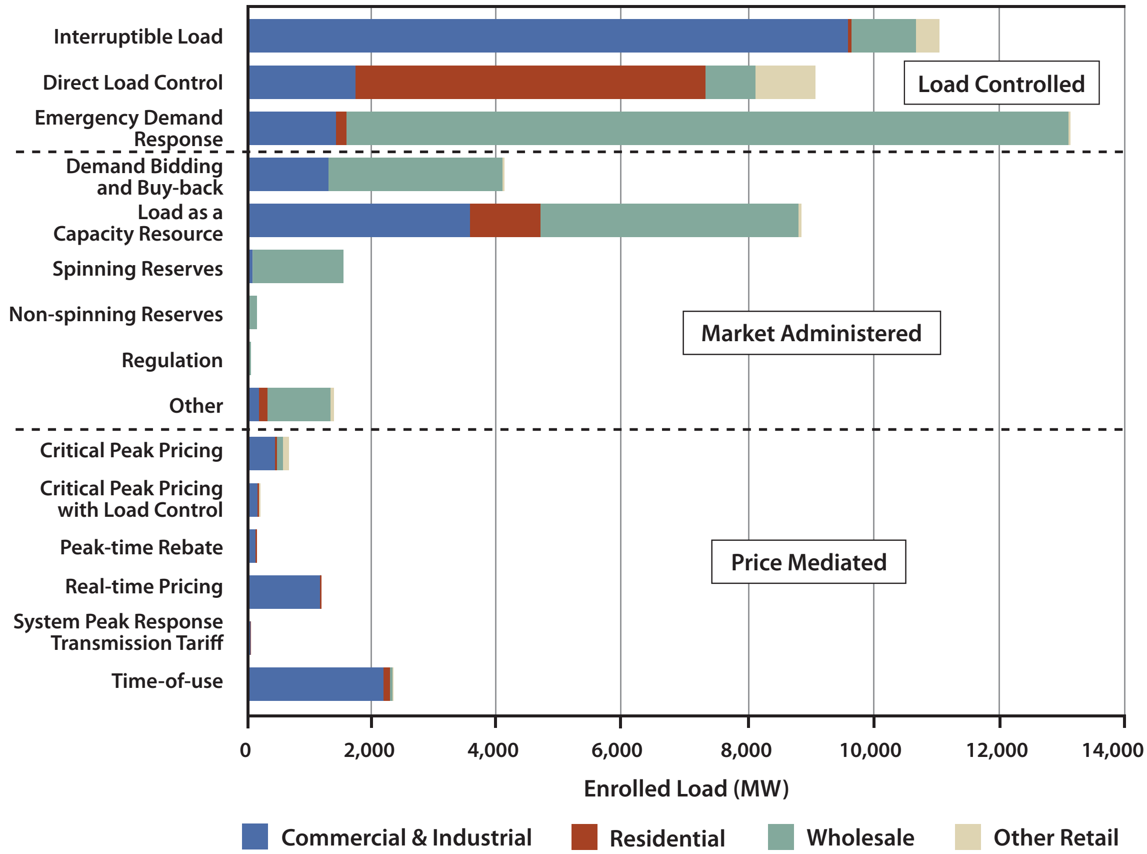
Finally, there may be opportunities going forward to use demand-side resources to help balance energy supply and demand in real time, especially for regions with significant variable energy resources, such as wind or solar generators. As noted in Chapter 3, if loads could be quickly and reliably adjusted, demand response might substitute for flexible supply-side regulation services or storage. The value of this responsiveness is likely to increase with penetration of VERs and the importance of loads that may be especially amenable to predictable, quick responses through automated controls, such as air conditioning and charging of electric vehicles. The feasibility of using demand response at scale for this purpose may vary widely across types of programs, and operational feasibility, particularly for purely price-mediated demand response, remains to be demonstrated. In addition, changes to market rules and reliability standards are required in some regions to allow demand-side resources to participate fully in the provision of balancing services.[16]

The designs of demand response programs used to accomplish these objectives are varied. They can be broadly categorized into load control, wholesale market–administered programs, and customer price–mediated programs, as shown in Figure 7.4.

Load Control Programs

Load management or control programs comprise the largest segment of demand response programs in place today. Used since the late 1960s by load-serving entities, vertically integrated utilities, and system operators to maintain reliability, they have more recently begun to incorporate broader peak-shaving objectives. The immediate and often predictable load reductions many of these programs provide are especially valuable in responding to system emergencies. They can also reduce costs by shaving the increasingly sharp peak loads described in Chapter 1 that are associated with increased penetration of air conditioning, falling industrial load shares, and retail prices that do not vary with system conditions.[17] While programs differ in operational details from entity to entity, they generally fall into three categories: emergency payment, interruptible tariffs, and direct load control. Enrolled customers typically receive a payment or rate credit as an incentive for participation. Load management programs contributed

Figure 7.4 Enrolled Load by Type of Demand Response Program and Customer Class



Source: Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering Staff Report* (Washington, DC, 2011).

approximately 62% of the nation's potential peak load reduction in FERC's most recent survey and continue to grow.[18] The aggregate load (MW) enrolled in different categories of load control programs is summarized in Figure 7.4.

"Emergency programs" are now the largest category of demand response program by enrolled capacity, propelled to this position by a dramatic increase in wholesale demand response enrollment. These programs provide incentive payments—ranging from $150/MWh to $1,000/MWh of curtailed energy use—to customers who curtail demand during reliability events.[iv] However, curtailment in emergency programs is generally voluntary and does not provide the grid operator or load-serving entity with the same degree of certainty of load reduction as direct load control or interruptible tariff programs. Emergency programs accounted for 25% of national peak reduction potential reported in 2010.[19]

[iv] These are in the range of maximum wholesale prices for generation in most U.S. markets. For example, 2010 maximum wholesale prices were $396/MWh, $343/MWh, and $1,102/MWh in the Southwest Power Pool, Midwest, and Electric Reliability Council of Texas regions, respectively.[20] Wholesale prices provide an appropriate benchmark for incentive payments because they reflect the cost of energy inclusive of grid conditions.

The second-largest category by enrolled capacity involves "interruptible or curtailable tariffs." These programs focus primarily on large commercial and industrial customers, who receive a rate discount or credit for reducing consumption during declared emergencies. In some cases, third-party aggregators may be able to combine smaller users to provide interruptible demand. Customers may face significant penalties if they fail to comply with a curtailment signal, which ensures that these programs achieve predictable load reductions when called. Interruptible tariffs comprised approximately 20% of national peak reduction potential reported in the 2010 FERC survey, and respondents indicated plans to substantially increase load enrolled in these programs.[21]

"Direct load control" programs, in which customer equipment or appliances are directly controlled by the load-serving entity or grid operator through switches or meter controls, constitute the largest category of demand response program by number of customers enrolled, and the third largest by total enrolled potential peak load reduction. Direct load control accounts for approximately 17% of the national peak reduction potential reported in 2010. Although these programs may be offered to all customer classes, participation has been particularly strong among residential customers, with more than 5 million enrolled residential customers. Central air conditioning cycling and electric hot water heaters, which comprise 70% of residential peak load nationwide, are the two most common targets of residential direct load control programs.[22] With loads under the direction of the system operator, these programs provide dispatchable load with high predictability of response. Respondents to FERC's 2010 survey report the greatest expected growth in direct load control programs over the near term, with enrolled load in these programs predicted to increase by 6,300 MW by 2015.[23]

As electric vehicle penetration increases, direct load control programs for charging stations may provide additional targets for enhancing demand response potential; see the discussion in Chapter 5.

Most load management programs are used relatively infrequently because they are designed to provide reliability under emergency conditions or, particularly for direct load control programs, peak shaving on a small number of hours during the year.

Most load management programs are used relatively infrequently because they are designed to provide reliability under emergency conditions or, particularly for direct load control programs, peak shaving on a small number of hours during the year. The amount of curtailment needed for reliability appears to be consistently much lower than available peak reduction potential. For instance, 14 out of 30 load management programs surveyed in 2001 were reported to have operated just once or not at all during that year, even though record-setting peaks were experienced in some parts of the country in that year.[24] In the 2010 FERC survey, respondents report actual reductions equivalent to 30% of the potential peak reduction. But when needed, these programs create considerable value. For example, New York Independent System Operator's estimated reliability benefits for each of four curtailment events during the summer of 2001 range from $800,000–$3.4 million, and aggregate reliability benefits over the entire summer totaled over $20 million.[25] It is difficult, however, to measure the dollar value of reliability-related peak reduction on a nationwide basis, particularly as its use, system conditions, and costs vary widely across the country.

While nothing intrinsic in incentive-based programs limits the frequency of their use, most operational experience has been with programs explicitly or implicitly designed to call for load reductions over a low number of days or hours of the year. One motivation for this has been concern about "demand fatigue," decreased customer responsiveness or exit from the program if called too frequently. This makes it difficult to extrapolate participation and response rates should the programs be broadened to pursue objectives other than reliability, such as peak load management. This may be a fruitful area to explore further in well-designed pilot experiments.

Wholesale Market-administered Demand Response Programs

A variety of new wholesale market programs for demand response has emerged over the past decade and is gathering momentum, as illustrated in the bottom panel of Figure 7.4.[26] Programs administered by independent system operators (ISO) or regional transmission organizations (RTO) contributed approximately 27% of national peak reduction potential reported in 2010. They can be categorized as capacity, energy price or demand bidding, and ancillary service programs. "Capacity market programs" are designed to incent market participants to commit to load reductions as a substitute for increased generating capacity. Enrollment in these programs has expanded as large customers bid into forward capacity markets, committing to future load reductions when called as a substitute for (unbuilt) new generating capacity. In contrast, "energy price programs" typically are day-ahead or hour-ahead programs for near-term commitment to consumption reductions. In many wholesale markets, customers are increasingly allowed to provide "ancillary services," such as spinning reserves, non-spinning reserves, and regulation, which are used to ensure the balance of supply and demand in real time. Ancillary service programs represent a very small but growing share of wholesale demand response, particularly in the Electric Reliability Council of Texas region.[27] Some ISOs and RTOs also compensate voluntary load reductions during emergencies on an energy price basis.[28]

Commercial and industrial customers along with wholesale purchasers comprise most of the load enrolled in wholesale programs. Large commercial and industrial customers can enroll and participate directly in these programs. Their volume of electricity consumption enables them to realize net savings even after bearing the costs of advanced meters and control equipment, and they frequently are better able to commit to transactions required for participation in wholesale programs, either directly or through aggregators. These factors enhance their attractiveness for increasing demand responsiveness in aggregate. Smaller customers can subscribe to services offered by third-party aggregators or "curtailment service providers," who, in turn, participate in wholesale programs on behalf of their customers.[29] The aggregator is responsible for finding the demand reduction should the utility or system operator call for load to be shed. For example, Comverge aggregated almost 8,000 MW of residential load through a variety of programs in 2010, either through long-term capacity contracts or programs it managed on behalf of utilities or other clients.[30]

Uneconomic behavior can be encouraged when some of these programs are layered on top of dynamic pricing tariffs. FERC Order No. 745 recommends paying the wholesale market price for reductions from baseline,[31] but when customers are not committed to purchase their baseline quantities of electricity, doing so generally will provide excessive compensation for reductions.[32] Customers facing high electricity prices generally will react by reducing usage; paying them in addition for those reductions amounts to double compensation. They will, in effect, be selling something they have not bought; they will both reduce their electric bills and be paid for doing so.

If customers have not committed in advance to purchasing a quantity of electricity or a particular load profile, determining the amount of demand response eligible for payment also requires a difficult counterfactual analysis. What would have been purchased but for participation in the program is inherently unknowable. Wholesale programs that compensate demand for reductions in load relative to a historic or administratively determined baseline provide incentives for customers to manipulate the baseline or act on their private information to profit from differences between the predetermined baseline and their true consumption patterns.[33] Demand participation in long-term capacity markets also raises questions of the verifiability and credibility of contracted demand reductions that may be promised several years in the future.

FINDING

Demand response programs that pay customers for reducing consumption from a baseline generally provide excessive compensation and give customers incentives for strategic behavior.

Price-Mediated Demand Response Programs

Price-mediated demand response programs face customers with retail prices that change over time to reflect variations in the market or opportunity cost of providing electricity. The principle underlying these programs is that customers will adjust their usage to consume electricity only when the value they ascribe to its consumption is higher than their cost of purchasing that electricity. The four most common time-varying pricing structures are time-of-use prices, real-time pricing, critical peak pricing, and peak-time rebates. These programs are much smaller than those in the previous categories. Aggregate enrolled load across all customer price-mediated programs contributed only about 8% of the national enrolled peak load potential reported in FERC's 2010 survey, with very little of that in the residential sector. But these programs may hold the greatest promise for future demand response.

As noted in Figure 7.4, the most common form of time-varying prices is "time-of-use tariffs." These enrolled roughly 1.1 million residential customers and 250,000 commercial and industrial customers, accounting for approximately 4% of the enrolled potential peak load across all demand response programs.[34] Time-of-use rates set a time profile of prices far in advance, usually held constant over a season. For example, summer time-of-use rates might set a low off-peak rate that applies to weekday nights, early mornings, and weekend hours, and a higher peak rate for use during weekday afternoons and early evenings. This predictable and stable time profile of prices can encourage customers to make long-term changes in their consumption patterns—for example, by avoiding dishwasher use during early evening. However, while the price schedule reflects the fact that costs are on average higher during periods in which demand is on average higher, time-of-use prices are not truly dynamic. They do not, for example, distinguish normal July weekday afternoon conditions from those on an unusually hot day with a spike in air conditioning loads or an unexpected outage at a large generating unit.

Dynamic prices can respond to those conditions, but dynamic pricing plans vary widely in the frequency of price changes. At one end of the spectrum is "real-time pricing," in which retail prices change hourly (or more often) to reflect actual variations in the system's marginal energy cost. At the other end of the spectrum are plans that layer time-of-use tariffs with an infrequently invoked price change for so-called critical peak periods. "Critical peak pricing" programs enable utilities to designate, a day ahead, a small number of days on which demand is expected to be exceptionally high relative to available supply. On those days, they charge a price for electricity consumed during peak hours that is several times higher than the usual time-of-use peak rate. "Peak-time rebates" operate similarly to critical peak pricing programs, except that customers are given a credit for reducing consumption below their administratively determined baseline during designated critical peak hours, rather than being charged a premium for consumption during those hours. Peak-time rebate programs suffer from the same baseline calculation challenges described above for wholesale market-administered demand response programs.

None of these dynamic pricing plans yet accounts for significant peak load reduction participation. Enrollment is comprised almost entirely of commercial and industrial customers, primarily larger customers within those sectors. Yet these programs can be quite cost effective. For example, several utilities in the Southeast—including Georgia Power, Duke Power, and the Tennessee Valley Authority—have long offered variants of critical peak, hourly day-ahead, or real-time pricing tariffs to their large customers, and they report considerable success in both customer satisfaction and peak demand management. Georgia Power estimated that its real-time pricing customers reduced peak demand by 17%, roughly 800 MW, during the early 2000s, roughly equivalent to eliminating one large baseload power plant from the necessary dispatch.[35]

Many utilities with limited penetration of dynamic pricing plans among their larger commercial and industrial customers are forgoing opportunities for significant cost-effective peak load management. Because interruptible load and emergency demand response programs are designed with different objectives and constraints, they are poor substitutes for dynamic pricing programs in this regard. Our report follows recent policy discussions in focusing on extension of demand response, particularly dynamic pricing, to the residential sector. But, there may be considerable gains to be realized from further penetration, particularly of real-time pricing, among large commercial and industrial customers.

Many utilities with limited penetration of dynamic pricing plans among their larger commercial and industrial customers are forgoing opportunities for significant cost-effective peak load management.

Why the focus on residential customers in policy discussions? Until recently, the high cost of required metering precluded extension of price-mediated demand response programs to most residential and smaller commercial customers. While metering costs to support dynamic pricing for commercial and industrial customers, estimated at 2010 US$750–$5,000 per customer connection, are higher than for residential users, they tend to be a smaller fraction of potential savings for large electricity purchasers.[36] The deployment of AMI technology across many systems now enables those utilities to offer residential customers at least one dynamic pricing option, perhaps in addition to existing non-dynamic rate structures, at little or no incremental cost. Whether and when utilities will do so is an open question. FERC's 2010 survey recorded some retrenchment from existing time-of-use and dynamic pricing programs, though that may in large part reflect changes in the survey methodology; there was some expected growth in dynamic pricing programs reported in plans for establishing future demand response programs.[37] The experiences of utilities that do implement dynamic pricing can provide insights on a host of important questions about customer education and service requirements, expected uptake of optional plans, and predictability of expected load response. We turn next to existing evidence on those questions.

Deployment of AMI and complementary technologies enhances potential demand response to supply conditions and may enable improved energy efficiency and conservation.

7.3 PREDICTING THE BENEFITS OF INCREASED DEMAND ENGAGEMENT

Deployment of AMI and complementary technologies enhances potential demand response to supply conditions and may enable improved energy efficiency and conservation. Estimating the expected magnitude of these benefits may be critical to determining the economic value of AMI-related investments—but the task poses considerable challenges.

Enhancing Demand Response

The aggregate benefits of introducing a new demand response program depend on the value of a given MW change in demand in response to a set of system conditions, the anticipated magnitude in MW of the response generated by the program, and the certainty of that response. Each factor is likely to vary substantially across service areas and among program designs.

The expected economic value of a MW of demand response is probably the most straightforward element to compute. It reflects the avoided cost of supply or shadow cost of supply constraints at a given moment, which system operators and utilities already calculate. This value is likely to vary across systems as well as over time. For example, many regions now operate with substantial reserve margins above expected peak demand as a result of past capacity investments, economic contraction, or population decline.[38] Increased enrollment in programs designed to reduce consumption at peak times is likely to generate minimal near-term benefits for systems that expect this situation to persist, even though the benefits could be substantial for systems anticipating inadequate peak reserve margins.

Measuring the expected impact of demand response involves predicting customer participation rates as well as customer response conditional on participation in a given program. Both may be difficult to assess. Analyses of demand response typically have focused on mean load changes across enrolled participants, paying little attention to modeling the determinants of participation or the certainty or distribution of load response. Some Recovery Act–funded pilot programs are now investigating these questions. Altering program design can compound the challenges. For example, changing a direct load control program's objectives from infrequent emergency or peak-shaving calls to a more frequent balancing role may make customer participation and response results from historical program data uninformative about future participation and response. Expanding the target population to add residential customers to a program populated by large commercial and industrial customers, or changing the tools—say, from direct load control to dynamic pricing—may require new experimentation and data to predict responses. Demand

Demand response mediated through dynamic pricing can be particularly challenging to value.

response mediated through dynamic pricing can be particularly challenging to value if system operators lack accurate prediction models for when, where, and how much load will respond.[v]

In light of these challenges, at least three sources of information may help to narrow the uncertainty in the benefits calculus:

- Simulation methods, which are useful to assess the general plausibility of a stylized economic case and determine which parameters or assumptions are most critical.

- Pilot programs and demonstration projects, which can provide feedback on parameters of customer response and impacts of variants in program design.

- Experience from large-scale deployments, which can help refine estimates of customer response over larger populations, longer time periods, and in the context of actual deployment. They also provide data on the actual costs of implementation and how those deviate from forecasts.

Simulation Analysis

Theoretical analyses of dynamic pricing can provide some insights on the source and likely magnitude of potential gains from broad deployment of dynamic pricing. Simulation analyses that have focused on system-wide deployment of real-time pricing yield some broadly consistent results:[vi]

- Real-time pricing schemes with prices that vary hourly or more frequently could reduce peak-period electricity consumption substantially under plausible demand elasticity assumptions. In the long run, this reduces necessary investment in peaking generating plants, leading to lower average electricity costs than would otherwise occur.[39]

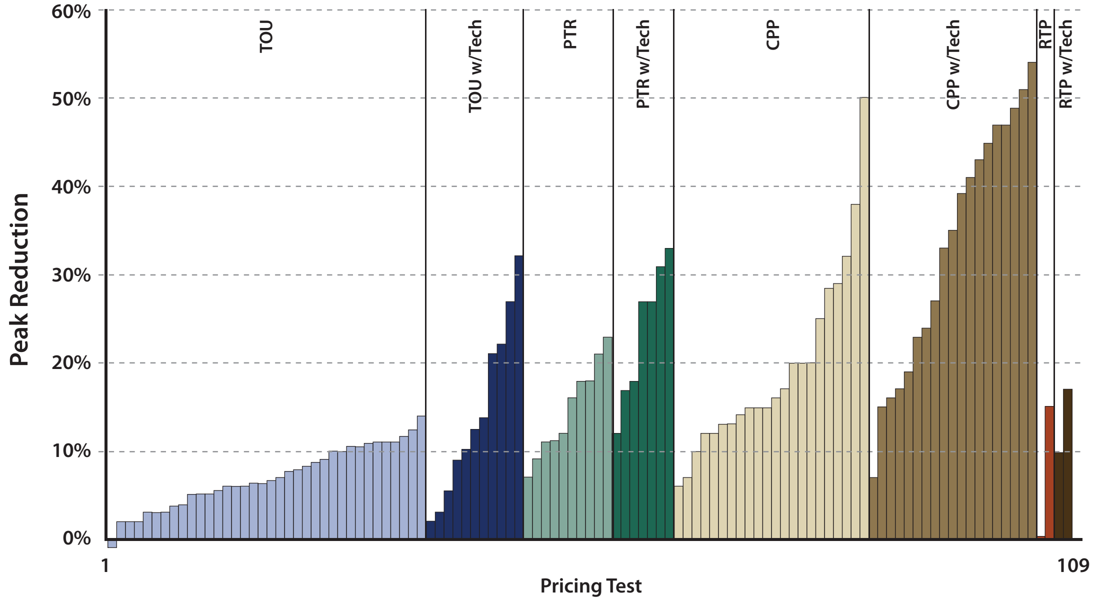
- A substantial fraction of the potential economic benefits of universal real-time pricing may be secured without universal penetration across customers: in simulations, putting less than a third of load on real-time pricing can yield roughly half the potential total benefits. Customers remaining on average cost-based flat rates will realize much of the cost savings that real-time pricing creates without adjusting their consumption patterns, indicating an issue of "free riding" in voluntary dynamic pricing schemes.[40]

- Dynamic pricing schemes do not necessarily reduce overall electricity consumption. While peak prices increase relative to flat rates, off-peak prices fall, which tends to encourage

[v] Some have expressed concern that this challenge may be so great as to threaten power system stability. For example, recent work illustrates the potentially destabilizing effect of price-responsive demand in a model of an ISO that uses only data on loads in past periods to forecast future load and sets price so that generation equals forecast load, ignoring past prices, the impact of price changes, and its own past forecast errors.[41] This analysis is closely related to the classic cobweb model in economics, which has little explanatory power in most settings because actors are more sophisticated forecasters than assumed in the model.[42] Forecasting load with reactive demand is difficult but soluble, as suggested by considerable experience internationally as well as in the U.S. with dispatch under customer-directed responses to emergency load-management, as well as wholesale price-mediated, customer time-of-use rates, and dynamic pricing programs.

[vi] A recent Institute for Electric Efficiency white paper simulates lifetime costs and benefits of AMI-facilitated demand response for four "prototype" utilities.[43] This paper probably is best viewed as providing a framework for analysis rather than simulation results for net returns to AMI investment, as a number of parameters are varied in ways that do not nest across prototypes, and the focus is on high-level aggregate returns rather than analysis of sensitivity to parameter values or modeling assumptions.

Figure 7.5 Peak Load Reduction from Dynamic Pricing Pilot Programs by Rate Design and Technology



Note: TOU=time-of-use pricing; Tech=technology; PTR=peak-time rebate; CPP=critical peak pricing; RTP=real-time pricing.

Source: A. Faruqui, "The Tao of the Smart Grid," presentation to the Michigan Smart Grid Collaborative, Lansing, MI, August 24, 2011, http://www.brattle.com/_documents/UploadLibrary/Upload973.pdf.

greater off-peak consumption as well as load-shifting. If off-peak consumption increases exceed peak-period declines, aggregate energy use will rise.[44]

- Real-time pricing exacerbates bill volatility. A substantial fraction of the annual electricity charges accrue during a very few, but very high-price peak hours, suggesting substantial swings in monthly bills—especially for customers whose demand is correlated with system loads (e.g., those who use more air conditioning at system peaks). Making available hedging strategies that can manage or reduce bill volatility is likely to play a significant role in encouraging the adoption of real-time pricing policies.[45]

In general, these simulation results are useful for assessing the qualitative impacts of dynamic pricing on electricity consumption. With their many simplifying assumptions and dependence on knowing realistic parameter values, however, theoretical studies cannot replace empirical evidence obtained from pilot projects, or better still, programs implemented at large scale.

Pilot Programs

In the last decade, a large number of small-scale and a few large-scale pilot programs have experimented with various forms of dynamic pricing at the residential level. Additional data will be collected over the near term as system-wide AMI deployments supported by the Recovery Act come on line. Unfortunately, data from most pilots typically have been inaccessible to outside researchers, making it difficult to draw general conclusions. Figure 7.5 is a summary presented by researchers at the

Brattle Group based on their proprietary data on 24 pilot projects implementing 109 variants of price and technology interventions.[46] In this figure, each bar represents a different price and technology variant and the height of the bars represent the peak load reduction observed. The results are grouped by rate design and whether the program provided customers with enabling technology, such as programmable controllable thermostats, energy lights or "orbs" that indicate high-price periods, or home-area energy management systems. The results are arranged in ascending order within each category of rate design and technology. The results suggest consistent evidence that consumers respond to dynamic prices by reducing their electricity consumption during high-price periods, in some cases, quite substantially.

Average peak load reductions by participating customers vary more than tenfold across the pilots.

As evidence that consumers will respond to price signals, these results are powerful. Extrapolating these results to make specific quantitative predictions is more problematic. The estimated average peak load reductions by participating customers vary more than tenfold across the pilots reported in Figure 7.5. Enormous response variation remains even when the results are grouped by rate design. This variation is in part explained by the magnitude of each pilot's price differential between peak and off-peak periods, the penetration of central air conditioning among the customer base, weather during the experiment, and the availability of automated technologies, all of which involve utility-specific adjustments.[47] Nonetheless, it appears that considerable heterogeneity persists even after many cross-study controls are employed.[48] For situations in which the quantitative magnitude of potential demand response is an important determinant of the business or policy case for AMI investment, additional data or econometric modeling may be necessary to improve the precision of expected mean reductions.[49]

Moreover, pilot project outcomes must be interpreted cautiously with attention given to the strength of individual pilot design and implementation quality.

Moreover, pilot project outcomes must be interpreted cautiously with attention given to the strength of individual pilot design and implementation quality. Several caveats should be highlighted:

- Most significantly, despite efforts to implement an experimental protocol with treatment and control groups, virtually all studies suffer in varying degrees from some form of selection bias in participation. In most cases, "treatment" (dynamic pricing) and "control" (standard tariff) groups were selected from customers who voluntarily participated in the pilot. In many experiments, customers assigned to the the dynamic pricing tariff (the "treatment group") were permitted to drop from the study and revert to standard rates. Discretionary participation implies that participants may be among the customers most willing to respond to price signals, and, as a result, may not be representative of the broader overall customer group.

- Pilot program participants may be representative of consumers enrolling under a similar optional dynamic pricing tariff in a given service territory, but extrapolating participation rates from one program type or area to another may be difficult. Determinants of participation rates appear to be one of the most significant unknowns in determining overall program benefits. Participation varies widely across pilots—for example, from 3% in Connecticut Light & Power's pilot to 20%, at least initially, in the California Statewide Pricing Pilot—and has not been carefully studied. Even if the selection at work in the pilots is related to the behavior of customers likely to participate in voluntary dynamic pricing programs, it will be difficult to predict responses to system-wide programs without information on the pilot protocol selection rule, the fraction of customers selecting into the pilot, and correlates of customer participation rates. This may make it difficult to match predicted participation from pilots to those for the tariff under consideration. Future pilots and system deployments should provide greater information and focus on participation determinants under optional programs.

- The quality of information provided by pilots varies widely. Many pilots enrolled relatively few customers, limiting the strength of statistical inferences and making it dangerous to generalize the results to the broader population. Others do not have adequate control groups or baseline data that allow analysts to measure treatment group responses against an untreated control group.

- Most pilot studies report relatively simple measures of responses, usually mean reduction in peak-period consumption relative to a baseline or control group's behavior, that mask a wide variance in the number of hours for which data are collected. In addition, there has been little analysis of the predictability of the mean response or the temporal distribution of responses by the group facing dynamic prices, though this information may be important to operate the system and assess the value of demand response. For example, a 5% peak reduction on every critical peak day may have dramatically different implications for system operation than a 10% reduction on half the critical peak days and no reduction on the remaining (perhaps hotter) days, though both scenarios imply a 5% mean reduction.

- Consumer responses to permanent dynamic pricing plans may differ from those in short-term pilot projects. Long-term responses may be greater, as when consumers invest in complementary technology or adopt new behaviors. They could be smaller if pilots attract greater consumer attention that wears off over time. Few pilots have measured residential responses for more than a few months or a year, although two studies that followed customers across two summer seasons report similar or increased responsiveness among those who participated in both years, suggesting the first effect dominated any short-term novelty or attention effects.[50]

- Few pilots have analyzed the distribution of responses or bill impacts across customers, though this may be an important input to regulators considering dynamic pricing plans (discussed in greater detail in this chapter). There is some evidence to show that most reduction in demand comes from a relatively small number of customers, but we do not know whether those could be identified in advance and targeted or how persistent their identity is over time.[51]

System-wide deployments of AMI combined with optional dynamic pricing tariffs may provide the data needed to fill in at least some of these gaps.

System-wide Deployments

System-wide deployments of AMI combined with optional dynamic pricing tariffs may provide the data needed to fill in at least some of these gaps. A number of utility systems have recently completed or will soon complete rollouts of AMI technology to all or most of their customer base as a result of utility initiatives, statewide legislative or regulatory mandates, or Smart Grid Investment Grant projects. Many of these utilities have proposed or committed to some form of dynamic pricing to follow the AMI deployment; some plan to offer customers a menu of pricing options. There is considerable heterogeneity in program design, including the dynamic pricing options that are offered, customer defaults and opt-in or opt-out rules, and availability of hedging or commitments that guarantee bills will be no higher under dynamic pricing than under historic tariffs during some specified transition period (a year is common). If data on responses to these programs are collected in a systematic and thoughtful way, this variety could help to refine or validate predictions for dynamic pricing impacts that come out of the pilot studies.

Deployments made with Smart Grid Investment Grant funding were expected to collect data on consumer responses under a structured experimental protocol, and deployments in systems not subject to these requirements also should collect and make available comparable data to facilitate learning and comparisons across installations. The scale of these programs, the diversity of the pricing schemes, and the ongoing, permanent nature of the installations are all likely to make information on consumer response of enormous value in improving our ability to assess the potential benefits of AMI-facilitated demand response programs. Efforts led by the U.S. Department of Energy to create mechanisms for utilities to share data from smart grid projects, including SmartGrid.gov (www.smartgrid.gov) and the Smart Grid Information Clearinghouse (www.sgiclearinghouse.org/), could yield significant social benefits, provided these data are made available to researchers and utilities that are not grant recipients. Unfortunately, such access remains uncertain as of this report's writing. Facilitating data collection and ensuring data accessibility could improve the design of dynamic pricing plans for utilities that have deployed AMI technologies and the quality of adoption decisions for utilities that have not yet committed to AMI.

7.4 REDUCING RESIDENTIAL ENERGY CONSUMPTION

Since the 1970s, many electric utilities have been tasked with improving energy efficiency, particularly for residential customers, and reducing energy use through programs that include a broad mix of targets that may range from energy-efficient lightbulbs and appliances to insulation and weather stripping. Energy-efficiency budget expenditures in 2010 exceeded $5.4 billion, an increase of 24% over 2009, of which 88% was in utility-administered programs.[52] Ratepayers typically fund utility-run programs in which all consumers pay a small surcharge on monthly bills to support the program budget, which may provide appliance rebates, energy audits, and subsidies for a variety of energy-enhancing home improvements to participating customers. These programs are associated with modestly reduced consumption, which recent estimates suggest cost an average of four cents per imputed kilowatt hour (kWh) saved,[53] comparable to the average wholesale electricity price or avoided generation cost in many regions of the country. This calculation does not include, however, many private costs of efficiency programs: the additional expenses in devices, equipment, or home improvements that consumers must incur to achieve the reduction in energy use. At these levels, costs largely offset the savings from reduced consumption, apart from any social externality associated with electricity use. This, combined with an objective of greater consumption impacts, has prompted industry and policy makers to search for new types of programs, focusing attention on potentially lower-cost behavioral interventions or potentially higher-impact programs based on informational feedback.

As noted earlier, a number of companies already offer commercial or industrial customers services that can use granular consumption data, such as that provided by AMI technologies, to suggest cost-effective modifications to reduce energy consumption. Much of the untapped potential for reducing electricity use may lie in residential behavioral changes and modifications to traditional consumption patterns.

The untapped potential for reducing electricity use may lie in residential behavioral changes.

Many experimental programs over the last several decades have assessed the impact of informational feedback on household electricity consumption. Average energy reductions in kWh ranged from 4% to 14% across a variety of programs on different continents between 1974 and 2010.[54] A recent comparison of direct feedback pilots using in-home displays reported reductions averaging 7%.[55]

However, energy-efficiency and conservation field experiments, perhaps even more than demand response pilots, frequently suffer from measurement, assessment, and design flaws that sharply limit the generalizability of their findings, may lead to unrepresentative or non-random samples of participants, and generally do not resolve whether the responses are long term or transitory. One of the more substantial recent projects tracked roughly 60,000 customers across treatment and control groups in the U.K. for a broad range of interventions (see Box 7.1). Despite considerable attention to program design and implementation, however, even these experiments confronted significant participant selection and dropout challenges.[56]

Feedback-based behavioral programs that provide a "social nudge" to consumers based on a positive norm of reducing electricity consumption have been the subject of increased experimentation in recent years. These appear to reduce consumption, although the magnitude of the effect tends to be consistently modest. For example, a recent analysis of a large set of data collected across 11 utility pilots (750,000 households) that includes pre-treatment observations, randomized treatment, and control groups reports average consumption reductions of roughly 2% across programs, with a range of 0.9%–2.9%.[57] Profiling and targeting programs to high-consumption households may increase the impact to around 6%, relative to pretreatment consumption levels. One of the very few experiments to report program costs and quantify the net economic impact suggests that behavioral interventions may be cost-effective, with program costs running roughly 2.5 cents for each kWh saved.[58] This estimate is based on a vendor-run indirect feedback campaign that makes use of mailings to customers and does not rely on technologies. Profiling, which targets behavioral intervention programs at those individuals most likely to respond, may further improve a program's cost-effectiveness.

The experience with feedback programs more broadly raises the question of whether it is the content of the feedback that leads to conservation, or simply the incidence of messaging. That is, do recipients of feedback find the information provided useful, or does the act of providing feedback serve as a reminder of conservation goals?[59] While this causal difference has not generally been tested systematically, some results are consistent with messaging being more important than content. For example, the combination of AMI and real-time display treatment was associated with reduced consumption for all the previously mention U.K. trials except Scottish Power's trial, which the final report speculated "may be related to the fact that the meter replacement [for Scottish Power] was presented as a routine replacement rather than as a smart meter or part of a research trial."[60]

BOX 7.1 THE OFGEM ENERGY DEMAND RESEARCH PROJECT

Of the many electricity systems that have undertaken pilot projects to evaluate the effects of informational feedback to customers, the Office of the Gas and Electricity Markets (Ofgem) Energy Demand Research Project in the U.K. is noteworthy because of its large scale, long time frame, and breadth of technologies and interventions.[61] Since 2007, more than 60,000 residential customers of four different energy suppliers participated in a variety of trials (roughly one quarter as controls), including tests of in-home display units, detailed billing, incentive programs designed to reduce or shift consumption, and advanced metering. University research centers assisted with independent statistical analysis and program design; the final project report was prepared by consulting firm AECOM.[62]

Highlights of the findings include the following:

- Programs focused on engaging and motivating consumers to reduce energy consumption with a combination of in-home displays and advanced metering generally were more effective than those without one or both of these technologies.
- The nature and quality of engagement with AMI installers appears to have influenced consumer responses, raising the possibility that behavioral interventions may be as significant as technology.
- While many of the interventions record consumption declines generally in the range of previous studies, there was limited consistency in energy savings across energy suppliers testing similar interventions.
- Consumers found price and cost data more useful than quantity or carbon emissions data.

Technical and management lessons from the project are informing the planned nationwide deployment of electricity and gas meters to enable the provision of informational feedback to consumers.

Given the current state of knowledge, the design of behavioral interventions to reduce electricity consumption seems a promising area for continued experimentation and research. This seems especially true of interventions that draw on fairly simple and inexpensive informational feedback. Initial experiments suggest that such programs can be designed and implemented at relatively low costs. Moreover, they could be a suitable near-term alternative to AMI-mediated technologies for systems that have not yet committed to broad AMI deployment. This is also an option for consumers who have access to AMI meters but for whom the cost-effectiveness of investment in additional energy management technologies is unclear.

FINDING

While a variety of programs suggest that energy savings are possible through informational feedback, the design of cost-effective behavioral interventions merits further experimentation.

7.5 EXPANDING DEMAND ENGAGEMENT: FINDINGS

As noted earlier, we believe that by 2030, AMI will be widely deployed across the U.S. and that dynamic pricing will be widely available, at least as an option. How individual systems will or should move toward that situation over time is much less clear. Although no one-size-fits-all recommendation can be formulated, some generalizations arise. We focus on these first in the context of systems that have already committed to universal deployment of AMI.

For utilities that are deploying AMI throughout their systems, dynamic pricing programs promise potentially substantial benefits.

For utilities that are deploying AMI throughout their systems, dynamic pricing programs promise potentially substantial benefits.[63] To realize this potential, utilities must carefully plan, stage, and support transitions to dynamic pricing that include extensive customer education, outreach, and service. Dynamic pricing plans are likely to be embedded in a menu of tariff offerings available to customers. Inducing general acceptance of dynamic pricing will require a different approach toward customer engagement than the one most utilities have taken in the past. This is highlighted in a recent report released by the Smart Grid Consumer Collaborative, which identifies key themes and best practices that emerged from its in-depth study of 21 organizations with successful customer-facing AMI, dynamic pricing, or efficiency programs.[64] Moreover, some pilots and early system deployment experiences suggest that customer service demands may actually rise, not fall, in the months following the installation of new meters, though most business cases assume call center and customer service expenses ultimately decrease with AMI installation. Regulators must be prepared to approve investments necessary to develop effective programs to engage customers and fund periods of higher customer service costs through the transition.

Implementing rate hikes or new price structures at the same time new meters are installed may exacerbate consumer resistance not only to the tariffs, but also to the technology itself.[65] Addressing this after the fact can be costly, as ongoing consumer protests over Pacific Gas & Electric's smart meter installations demonstrate. Strategies utilities have adopted to mitigate potential adverse reactions include running AMI side-by-side with existing meters for some time, offering bill comparisons of charges under current and future tariffs based on actual consumption data for the period, and providing maximum bill guarantees for a specified term following take-up of a dynamic pricing plan. Utilities and their customers are likely to gain if best practices for transitions are analyzed and widely shared.

Competition in electricity retailing may complement AMI deployment in hastening the development and penetration of dynamic pricing options and their associated benefits, provided that appropriate default service tariffs are established or the monopolies that provide distribution services (so-called wires firms) are excluded entirely from the business of selling energy.[66] Retailers that can successfully reduce their customers' usage during periods with high wholesale prices—through dynamic pricing tariffs, energy management technologies, or direct load control programs, for example—will reduce their average energy acquisition costs and consequently can offer their customers lower average bills. A monopoly utility has the same opportunities but may have weaker incentives to innovate (see Chapter 8). It needs to obtain approval for new rate structures from its regulator (or equivalent, if publicly owned) in an inherently political environment. Given customer resistance to change, utilities and regulators may have strong incentives to be cautious and find relatively little to be gained by confronting that resistance. Competitive retailers, in contrast, have strong incentives to find ways to use the benefits of dynamic pricing to win customers. Retail competition consequently may encourage greater experimentation than most regulated monopolies will undertake.

FINDING

Well-designed and well-executed customer engagement programs and tariff transition policies are needed to avoid customer backlash to AMI technology and dynamic pricing plans. Retail competition, where implemented appropriately, may facilitate dynamic pricing.

Concern about distributional impacts of dynamic pricing, particularly for lower-income households, may impede transitions to dynamic pricing under monopoly retailing. This should not be seen as insurmountable. Many low income consumers may have flatter than average consumption profiles, suggesting a benefit from dynamic pricing without any demand response. Moreover, while few pilots have focused specifically on low-income consumers, one recent analysis of data from several pilots suggests that low-income customers respond to higher prices, though in most cases, their demand responsiveness in terms of peak load reduction was below the mean for all customers in the program.[67]

Dynamic pricing plans may eventually come to be viewed as more equitable than flat-rate tariffs because they allocate more of the cost of consumption to those who are responsible for imposing those costs on the system. The constant rate structure applied to most retail electricity customers—and virtually all residential and smaller commercial customers—subsidizes customers who impose higher costs on the system, such as those with peak demands that are coincident with system peaks.[68] Customers with less peaked demand profiles may be inherently less costly to serve and may benefit from dynamic pricing.[69]

Moreover, ways to limit distributional impacts exist. For example, the peak rebate tariff tested in the PowerCents program coupled a basic time-of-use rate with rebates for peak-hour consumption reductions relative to baseline on preannounced critical peak days. This provides a form of insurance: customers gain from reducing peak electricity use but do not pay higher rates if consumption is unchanged. To be clear, providing this insurance on a system-wide basis is not free. Peak-time rebates may provide incentives for customers to raise baseline consumption to increase their potential rebate and tend to be associated with lower mean responses than critical peak pricing plans, as shown in Figure 7.5.[70] The level of base rates also must be high enough to cover the revenue needed to pay for rebates to customers who adjust peak consumption, suggesting that consumers who do not participate in peak-period reductions eventually may experience higher average bills, all else equal. But all else may not be equal: demand response by even a fraction of consumers may reduce system-wide energy costs, offsetting part or all of this effect on base rates.[71]

Dynamic pricing plans may eventually come to be viewed as more equitable than flat-rate tariffs because they allocate more of the cost of consumption to those who are responsible for imposing those costs on the system.

While regulators in some jurisdictions have agreed to make time-of-use or dynamic pricing plans a required or default contract for large commercial or industrial customers, there is widespread reluctance to require smaller customers—especially residential customers—to enroll in time-varying tariffs. If participation is voluntary, as we expect it will generally be at least initially, the available evidence suggests that opt-in plans generally lead to much lower participation rates than default, or opt-out, plans.[72] Experimentation may be needed to determine how best to design customer choice into dynamic pricing plans. As argued here, retail competition may provide stronger encouragement to such experimentation than regulated monopoly.

FINDING

Concern about the impact of higher or more volatile bills, particularly for low-income consumers, may limit the perceived political viability of dynamic pricing but this can be addressed by well-designed menus of rate options.

Consumers may be able to respond manually in limited ways and at relatively low cost to some forms of dynamic pricing. For example, in critical peak pricing programs, consumers are told the day before about price spikes and can decide to adjust consumption accordingly. But it seems unlikely that many consumers will want to spend a lot of time and effort managing their electricity usage, particularly when the overall bill impact may be small.[73] One of the most consistent findings across pricing pilots is the much greater responsiveness of demand in the presence of enabling technologies. This could be something as simple as a programmable controllable thermostat, which can receive price or other signals from the distribution system and adjust air conditioner load automatically based on preassigned instructions, or an energy "orb" that signals high price periods by changing colors. Or consumers could opt for more complex and expensive home energy management systems that integrate "smart" automated appliances, HVAC systems, and other major loads and optimize use based on granular consumption data from solid-state meters, customers' price and comfort preferences, and utilities' price signals.[74] Implementing complex dynamic pricing schemes before low-cost enabling technologies are available may limit realized benefits and cost-effectiveness, and doing so may also lead to consumer frustration as bills increase because consumers cannot easily avoid high-cost consumption.

Implementing complex dynamic pricing schemes before low-cost enabling technologies are available may limit realized benefits and cost-effectiveness

Of course, there is a chicken–egg issue here: without dynamic pricing, enabling technologies offer few benefits, and accordingly, there will be little incentive to develop or deploy them. Attempting to install enabling technology across a utility's entire customer base is likely to be unnecessarily expensive even with dynamic pricing tariffs, especially if enrollment in dynamic pricing plans is not mandatory. While consumer participation rates in demand response programs have not been well-studied, most analysts agree that enrollment will be far less than universal.[75] The most cost-effective solution is likely to involve assignment of the responsibility for technology installation decisions, ownership, and payment to participating customers. We would expect third-party service providers or, if present, competitive retailers to be active in this market if policies do not restrict their activity or embed enabling technology investment in utility ratebases.

FINDING

Capturing significant benefits from dynamic pricing is likely to require investments in complementary technologies, particularly those that permit customers to automate their responses to price changes.

Finally, we turn to those utilities that have not yet committed to a system deployment of AMI. As noted in Chapter 6, for some utilities, the pure operational benefits of AMI may fall far short of the cost of deployment. This may be especially likely for systems that have recently installed automated meter reading (non-AMI) systems throughout their customer base. Where operational benefits are low relative to deployment costs, systems may be reliant on demand response and conservation benefits to make a business case for investment. For these systems, AMI investments are not yet sunk. Their net benefit of expanding residential price-responsive demand may not be not clear, particularly because, at present, there is considerable uncertainty about both the cost of AMI and its required associated technologies, and the precise magnitude of demand response benefits that investment would produce.

Using AMI to enable real-time pricing or other demand response programs requires significant expenditures by the distribution utility in meter data management systems, information technology, and customer education and service, in addition to meter acquisition and installation costs. Many customers may choose not to participate in demand response programs, at least for some time. For these customers, the full metering cost is incurred with no prospect of demand response benefits as offsets. Utility rate filings, such as those surveyed in Chapter 6, suggest that the expected all-in cost of AMI deployments averaged perhaps $300 per installed meter over the past five years, though more recent industry estimates suggest a possible decline to $150–$250 per meter.[76] Moreover, customers choosing to participate in voluntary demand response programs are likely to incur additional investment costs for enabling technology—which may be as complex and expensive as a separate home-area network or as simple as a programmable controllable thermostat. Whether those costs are paid directly by the customer, a third-party aggregator, a competitive energy retailer, or, in some cases, the distribution utility itself, they belong in the economic cost–benefit calculation.

Actual costs of deployment may differ from the prospective estimates submitted in utility proposals because of the lag between submission, approval, and subsequent staged deployment over a few years. Predictions may be especially uncertain for the costs of information technology, customer education, and customer service. Fortunately, information on many of these is likely to improve considerably over the near term. Similarly, as systems implement price-mediated demand response programs, estimates of demand response participation rates and system benefits are likely to improve.

FINDING

For systems with limited operational savings from AMI, the economic value of early replacement of existing meters with new AMI meters is uncertain due to limited information on both the "all-in" costs of deployment at scale and the expected demand response benefits. Current deployments are likely to improve the quality of information on costs and benefits and thus enable better decision-making.

7.6 CONCLUSIONS AND RECOMMENDATIONS

We confidently expect the demand for electricity to become increasingly responsive to system conditions, to an important extent because of increased adoption of dynamic pricing over time. The value of making demand more responsive will increase as VERs, pure electric vehicles, and plug-in hybrid vehicles become more important and concerns for system efficiency persist or intensify.

Complementing this, new technologies, particularly AMI, are reducing the cost of transmitting fine-grained, real-time price signals to customers and of both automating and measuring their responses. But, the path from today's flat-rate pricing system for all but the largest commercial and industrial customers, to a system in which some form of time-varying prices becomes the default for many if not all customers, is likely to differ across utilities. Because AMI deployment is both a major investment and essential for truly dynamic pricing, our recommendation for how to proceed depends on whether a utility is presently committed to widespread AMI deployment.

Early AMI Adopters

Many utilities have already made commitments to universal AMI deployment throughout their systems; in fact, some have already accomplished that objective. For other utilities, AMI investments may pass cost–benefit tests without requiring any significant demand-side benefit, and we would expect those commitments to be made. For example, systems that operate manually read, traditional electromechanical meters and those with low customer density, high customer turnover or high billing losses may find that the operational cost savings from reduced meter-reading labor, outage detection, remote connection and disconnection, and theft reduction largely offset the capital costs of universal AMI deployment across their service area over an estimated 20-year useful meter life.[77] These systems may find the economics of near-term AMI investments attractive and join the utilities that have already committed to AMI.

Early adopters confront a number of challenges and responsibilities. Home energy management systems, automated residential appliances, and other complementary technologies are relatively immature and costly. Capabilities and costs are improving rapidly, and the direction of innovation is difficult to predict. In addition, consumers are concerned about the privacy and security implications of AMI. The system standards for cybersecurity are in the early stages of evolution, as discussed in greater detail in Chapter 9. Stranding consumer or utility investment in meter or control technologies that are not compatible with later generations could be quite costly. Ensuring that new meters and any associated equipment installed by the utility offer interoperability with current and potential new communications and "behind-the-meter" technologies is essential to preserving the value of these investments.

For the many utilities that have already installed AMI technology across their systems or are committed to doing so, the largest cost of enabling greater demand engagement via dynamic pricing has been sunk, particularly if their information technology systems have simultaneously been upgraded to accommodate the data flow from AMI systems. If dynamic pricing tariffs are offered but not mandated, as seems likely at least initially, default service tariffs should be designed to reduce subsidies to flat-rate customers and encourage efficient evolution toward universal dynamic pricing defaults over time.

Structuring demand response program implementation using best-practice pilot design will enhance the ability of researchers to measure programmatic impact. For example, utilities should collect baseline consumption data before exposing consumers to new rate designs and may stagger the rollout of new rate options across service areas to provide a synthetic control group. This structure also can improve a utility's ability to allocate customer service resources and respond effectively to any unforeseen problems that develop in implementation.

These requirements should be viewed not as impediments but as requisites to effective implementation. As in many other areas, sharing information gained from innovative programs and investments is critical to efficient evolution at the national level. Smart Grid Investment Grants were designed to have a crucial information-sharing component, and the Department of Energy has led efforts to create mechanisms for sharing data via www.smartgrid.gov and the Smart Grid Information Clearinghouse (www.sgiclearinghouse.org/). Ensuring timely reporting to these repositories, using them to collect similar information for deployments that were not supported by stimulus funding, and making data accessible to both industry participants and researchers outside the utility sector are critical to realizing the greatest value from early AMI adoption.

RECOMMENDATION

Where a commitment to AMI technology is already in place, investment decisions should focus on interoperability and compatibility with later generations in meters and associated technologies. Utilities should design and follow a transition path that includes appropriate investments in customer education and engagement programs to encourage migration to universal dynamic pricing, with an ultimate goal of substantial real-time pricing penetration. Early adoptions have an important research and demonstration component: information on investment costs and the results of demand response programs should accordingly be collected and shared widely.

Systems without Present AMI Commitments

For many other U.S. utilities, operational benefits of universal AMI deployment may offset only 50%–60% of the system installation costs. This is likely to be the case for many of the utilities operating the roughly 50 million non-AMI meters now deployed in the U.S. that can be read remotely. These meters capture a significant fraction of the reduced meter-reading costs promised by AMI technologies, and they may have many years of useful life remaining. In this case, investments in AMI might range from significantly uneconomic to substantially positive in net present value, depending on uncertain implementation costs and demand-side benefits. Utilities in this situation may rationally decide not to commit investment dollars to AMI until some uncertainty is resolved.[78] Crucially, AMI investment decisions are not "now or never," but rather "now or reconsider next year."

AMI investment decisions are not "now or never," but rather "now or reconsider next year."

Waiting until lessons are learned from the first wave of AMI installations may yield myriad benefits. The capability-adjusted costs of AMI and complementary technologies seem likely to decline as innovation advances and manufacturers gain greater experience and scale in production. Given the volume of existing AMI installations and those committed to completion over the next few years, the quality of information on deployment costs and the range of demand-side benefits also is likely to improve considerably in the near term. Utilities that have not yet committed to AMI rollout have the option to wait while this information is collected and then revisit the decision. Deferring deployment decisions also reduces the chance that a utility will be locked into an early but inferior technology.

This does not imply that utilities in this evaluation mode must forego residential demand response. For example, as noted earlier, direct load control programs targeting air conditioning and electric hot water heating have substantial current enrollments in some utility service areas. Direct load control programs could be expanded on both the intensive margin—increasing the frequency or set of circumstances under which utilities can invoke load control—and the extensive margin—expanding the set of utilities and customers using direct load control. Electric vehicle charging may offer additional opportunities for direct load control in regions with significant electric vehicle penetration. These programs do not require universal AMI for implementation and may be a highly cost-effective alternative or complement to dynamic pricing for many customers, even where AMI is installed and especially where it is not.[79]

RECOMMENDATION

The decision whether to adopt AMI need not be made immediately. Decision makers should recognize the option value of waiting to learn from early deployment data on costs, technologies, customer responses, and demand response program design and benefits.

To be clear, we are advocating care, not indefinite delay. We expect by the end of our study horizon in 2030, most, if not all, U.S. utilities will have rationally deployed AMI technologies, and we hope that policy makers will have facilitated movement far along the path to universal dynamic pricing.

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Chapter 8: Utility Regulation

The challenges and opportunities described in earlier chapters place increasing burdens on electricity system regulators. Issues specific to transmission were discussed in Chapter 4; the discussion in this chapter focuses on utility regulation in general terms, with particular attention on the determination of retail rates and treatment of investments. While various reforms of public utility regulation have long been debated, the impending changes will escalate regulatory policy design to higher prominence.

The chapter starts with an introduction to the primary objectives and current practices that guide setting electric utility rates. Although all forms of utility oversight generally reflect a common set of objectives, the details vary for different types of utilities. Section 8.1 gives an introduction to some of the most important distinctions and provides background for the findings and recommendations that follow.

Section 8.2 discusses emerging challenges for regulatory policy, beginning with the changing nature of utility investments. Many of the grid investments described in this report present greater risk than has been common over the past several decades. Next, we discuss customer incentives in the context of traditional rate structures. Recovering a substantial portion of distribution and transmission network costs through volumetric kilowatt-hour-based rates distorts both utility and customer incentives and over time may create implicit cross-subsidies across subsets of customers. Section 8.2 also discusses the stress that rising rates can put on regulatory processes, and the potential tension between a regulated franchise monopoly mind-set and distribution system innovation.

Section 8.3 assesses tools that might improve regulation of the U.S. electric power system in the context of the challenges outlined in the first two sections. These inform the conclusions and recommendations summarized in Section 8.4. We first find that consistent cost and performance metrics would allow for better comparisons of utility performance over time, and recommend that regulators collaborate to develop and publish such metrics, and that those with utility oversight authority ultimately tie utility outcomes to their performance on those metrics. Second, we find that new mechanisms for risk allocation and compensation are needed to balance incentives for risky investment with investment cost discipline, and we encourage continued experimentation and regulatory innovation in this direction. Finally, we find that alternatives to volumetric charges are needed to mitigate distortions common to most utility rate structures, and we recommend that fixed transmission and distribution network charges be recovered largely through customer-level fixed charges.

The U.S. electric power industry must invest significant amounts of capital over the coming decades to replace aging assets and expand the network to meet incremental load growth. That investment easily could double if utilities deploy new transmission and distribution technologies to improve system operation; enhance service quality; and accommodate new types of generation, load, and demand response.[1] To deliver on these promises in the most efficient and cost-effective manner, the regulatory systems and policies that oversee the U.S. grid also must be modernized.

8.1 REGULATORY OBJECTIVES AND PROCESSES

As described in Chapter 1, the organization of electricity systems in the U.S. varies widely. Until the 1990s, the industry was dominated by vertically integrated, investor-owned utilities (IOUs) that provided generation, transmission, and distribution services under rates that state public utility commissions regulated. In the late 1990s, independent transmission system operators (ISOs) were established in much of the nation. A number of states in ISO regions restructured their electric utilities by separating generation from transmission and distribution, and some states enabled competitive retail service, particularly for larger commercial and industrial customers. Generators in ISO regions sell into competitive wholesale markets for energy that is managed by the ISO, and distribution utilities and retailers purchase energy from those markets.

Some of the larger government-owned systems were and are vertically integrated, but most government and cooperatively owned systems are smaller utilities that purchase most or all their energy and transmission services from vertically integrated firms or independent power producers. They provide only distribution services to customers in their jurisdictions. The considerable heterogeneity in ownership, organizational, market, and regulatory forms limit generalizations across U.S. electricity systems, but some commonalities exist in core aspects of price determination.

First, distribution services are universally treated as a natural monopoly. Even in areas that have restructured their electricity markets, delivery of electricity from the high-voltage transmission network to end-use customers generally is assigned as an exclusive franchise to a government-owned or cooperative enterprise or to an IOU subject to some form of price regulation. In this chapter, we will refer to all such entities as "distribution utilities," recognizing they may be parts of vertically integrated organizations. Depending on the jurisdiction, generation and transmission assets—including transmission lines, the hardware and software in control centers, and various other sorts of equipment—also may be owned by entities of all these types.

Second, the prices for franchised monopoly services generally are determined administratively. State public utility commissions regulate the prices IOUs charge through proceedings known as "rate cases." City councils or independent boards oversee government-owned utilities. Customer-owned cooperatives are governed through committees or boards comprised of their members. The principles that

The principles that govern rate determination are broadly similar across each of these organizational forms.

govern rate determination are broadly similar across each of these organizational forms. When we refer to "regulators" in this chapter, we generally include entities responsible for supervising publicly and cooperatively owned utilities. Regulators universally determine the allowed cost recovery for distribution services; the cost of generation or wholesale power purchases and transmission is passed through according to rules that vary across regimes.

Third, utility oversight generally reflects a common set of objectives:

- **Operational Efficiency:** Utilities should deliver the quantity of electricity that consumers wish to purchase at the lowest reasonable cost while providing acceptable reliability and other aspects of performance.

- **Dynamic Efficiency:** Utilities should make efficient investments in innovation so that they are able to meet future demands at the lowest reasonable cost.

- **Consumption Efficiency:** Customers should bear the incremental cost that their decisions impose and be given appropriate incentives to consume electricity only when its value to them is at least as great as the incremental cost of producing and delivering it. Prices should be set at the lowest level consistent with system cost recovery and investment incentives, with "cost" understood to include a fair rate of return on capital to investors or compensation for public capital for non-IOUs.

- **Other Policy Objectives:** Where utilities are expected to support other policy goals, they should do so in a cost-effective, minimally distortive manner. Regulators frequently establish distributional goals, such as requiring firms to design rates such that customers who are thought to be better able to pay bear a larger share of network (non-energy) or other regulated costs. Other goals may include enhanced energy efficiency and accommodation of renewable generation, distributed generation, or electric vehicles.

One of the greatest challenges facing regulators attempting to implement these objectives is asymmetric information: while a utility's demand characteristics and opportunities for cost reduction and investment may be fundamentally uncertain, managers of the utility typically have better information on these than does the regulator. As a general matter, this makes it impossible to simultaneously ensure exact cost recovery and provide optimal incentives for cost minimization.[2]

Two extreme theoretical regimes illustrate this problem. Pure cost-of-service regimes set utility revenues at all times exactly equal to observed utility costs, including a normal return on investment in the rate base. These schemes ensure full cost recovery because the regulator can generally measure actual costs precisely. But they provide no incentives to managers to exert effort to minimize those costs.

One of the greatest challenges facing regulators attempting to implement these objectives is asymmetric information.

In contrast, high-powered, incentive-based regimes decouple a utility's revenue from its actual costs. In a textbook price cap regime, for instance, prices are set once and remain fixed over time. This provides strong incentives for cost reduction because a dollar of cost savings translates into a dollar of profit. But revenues may greatly exceed costs or be far below them for any given utility or at any point in time.

While actual regulatory practices depart from these theoretical extremes in significant ways, processes based broadly on cost-of-service regulation determine most U.S. retail electricity rates.[i] The mechanics of this regulatory process divide into two broad tasks:

- determining the utility's total cost—including a fair rate of return on prudent capital investments—which forms the basis of a total "revenue requirement"; and

- setting rates by allocating a share of required revenue to each customer class and determining the structure of rates to recover that revenue.

These processes play an important role in determining utility and customer incentives.[3]

[i] Municipal, cooperative, and other non-IOU systems typically determine rates through different processes, but they lead to similar outcomes as cost-of-service regulation and involve similar efficiency problems.[4]

One important way the practice of cost-of-service regulation differs from the theoretical extreme characterization is that only the costs that regulators deem prudent are recoverable through the ratemaking process. This oversight process is particularly important for capital investments. Generation investments by IOUs outside competitive wholesale market areas and distribution system investments for all IOUs are subject to state commission review and rate regulation. Similar reviews apply to capital investments by publicly and cooperatively owned utilities. As discussed in Chapter 4, regulators of various sorts must give their approval before entities can build new transmission lines, and state commissions and the Federal Energy Regulatory Commission regulate the returns to rate-based transmission investments by IOUs.

Experiential learning is important for the prudency review process: over time, regulators develop familiarity with the types and levels of investments required to provide acceptable service for a given utility system and set of technologies. While utilities and regulators sometimes may disagree—for example, because of different views of the optimal level of reliability—most traditional distribution system investments have been relatively low risk, and reviews generally have been routine. Generation and transmission projects typically involve more significant outlays and, accordingly, receive detailed project-specific reviews.

We refer to network costs—the capital and operating costs of the distribution and transmission network—as "fixed costs" because they are largely unaffected by short-run changes in kWh energy consumption.

We refer to network costs—the capital and operating costs of the distribution and transmission network—as "fixed costs" because they are largely unaffected by short-run changes in kWh energy consumption. These costs are also relatively stable between rate reviews. In contrast, energy costs—reflecting either fuel costs for vertically integrated utilities or wholesale power acquisition costs for distribution utilities in restructured markets—vary with electricity consumption and change with fuel prices, among other factors. Fluctuations in energy costs generally flow through to rates via frequently changed volumetric energy charges—that is, charges applied to each kWh consumed—often implemented by automatic adjustment formulas indexed to costs.[ii] In some jurisdictions, a portion of distribution service rates also may be subject to an automatic adjustment between rate cases.

Once the required revenue for cost reimbursement has been determined, the regulator must decide how to set rates to recover those costs. To determine customer charges for distribution, network costs at the distribution level typically are first allocated to customer classes based on such factors as connection voltage and the class's estimated contribution to the local peak demand. Rates are computed to match the total cost allocated to each customer class to expected revenue, based on historic consumption levels and usage patterns for that class. All customers face distribution rates that are at least partially volumetric. For large customers, volumetric distribution charges tend to be low, and most of the allocated costs are recovered through fixed monthly charges, typically based on that customer's actual peak demand level during some prior base period or its contracted demand for some future period. In contrast, distribution and transmission system costs are recovered from small commercial and

[ii] In competitive retail markets, the retailer determines the contractual energy price, which is combined with the regulated transmission and distribution charges into a single customer bill.

residential customers almost entirely through volumetric delivery rates ($/kWh), with very low fixed monthly customer charges in virtually all jurisdictions.

Revenue adequacy for the distribution utility is met by matching the expected aggregate revenues across all customers, given rates and expected levels of consumption, to the revenue required to match total allowed system costs. In another departure from the theoretical model of pure cost-of-service regulation, those rates generally are then fixed until the next regulatory review, apart from the impact of any automatic adjustment formulas.

The detail of charges customers see on their bills varies tremendously across jurisdictions. Many customers receive bills that aggregate energy, transmission, and distribution charges into a (generally small) fixed monthly customer charge and usage charges based on kWh consumption, often with two or more steps that increase the kWh charge as monthly consumption rises above threshold levels (a structure known as "increasing block pricing"). In some jurisdictions, notably those with retail competition, bills may be "unbundled," with separate charges detailed for energy, transmission, and distribution, each of which may change across usage "steps." As noted in Chapter 7, the delivered electricity rates are constant within a billing cycle for most residential and small commercial customers. Larger commercial and industrial customers are more likely to face rates that vary with time of day and day of the week, and for some, with system conditions.

Between 1990 and 2010, the annual average increase in the Consumer Price Index was only 2.6%, and average retail electricity rates increased by only 2.1% per year on average.[5] A variety of factors contributed to this performance, among them efficiency gains in generation as a consequence of competitive wholesale electricity markets and, in networks, because of incentive-based regulation.[6] In this low-inflation environment, utility ratemaking overall has functioned relatively smoothly, unlike some earlier periods when costs were rising more quickly.[7] But changes in the economic environment and the demands placed on utilities are likely to increasingly strain the existing regulatory system during the coming decades, increasing the value of regulatory adaptation and innovation.

8.2 GROWING CHALLENGES FOR REGULATORY POLICY

Several factors will combine to increase the likely stress on existing regulatory practices in the coming decades. Many will arise from the significant investments in new technologies that systems may need to make to improve system operation and accommodate new demands on electricity networks, as described in previous chapters. Traditional regulatory approaches have difficulty assuring that incentives and compensation for such investments lead to cost-effective decisions. Paying for increased network investment, combined with higher power costs that may arise from policy mandates, such as renewable portfolio standards, is likely to require electricity rate increases. Rising rate levels challenge most regulatory systems. Prevailing rate structures may compound the difficulty of managing increases, both by limiting demand engagement, as discussed in Chapter 7, and by giving some customers the incentive and ability to shift part of their share of network costs onto other customers, as we describe below. Finally, innovation in customer-facing activities may not be well-matched to the focus, skill set, and incentives of traditional utilities or their regulators.

Paying for increased network investment, combined with higher power costs that may arise from policy mandates, such as renewable portfolio standards, is likely to require electricity rate increases.

The Nature of Investments Is Changing

Meeting the future expectations for transmission and distribution systems in a cost-effective manner will require utilities to evaluate and potentially adopt technologies that significantly depart from traditional grid investments. Among the required new capabilities are automated sensing and control (Chapters 2 and 6), development of more responsive demand (Chapter 7), and accommodation of variable energy resources, distributed generation, and electric vehicles (Chapters 3, 4, and 5). The total cost of integrating large amounts of variable energy resources and distributed generation in particular will depend on the degree of automation and active management of the transmission and distribution networks, and there are no system-scale deployments in existence to serve as models.[8] Electric vehicles may require distribution network component upgrades, although their timing and magnitude depend critically on the penetration and geographic distribution of electric vehicles within the distribution system and how charging is metered, controlled, and priced.

Ideally, utilities would invest in risky new technologies if the expected returns when the technology is successful are at least sufficient to compensate for possible losses if the technology fails. In theory, cost-of-service regulation encourages utility capital investment by assuring utilities a "fair" rate of return on their investment. This suggests that regulated utilities might be eager to undertake investments of all sorts, risky or not. In practice, however, the uncertainty associated with new technologies and risk aversion on the part of regulators and utilities may discourage even efficient investments.

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Utilities considering significant capital investments generally seek to reduce the regulatory uncertainty through *ex ante* prudency reviews. But for many new transmission and distribution technologies considered in this report, neither the utility nor the regulator may have much, if any, experience assessing the technology.[9] Forecasting the level of capital expenditures, net change in operating costs, and system benefits of emerging technologies can be difficult in such situations. Without good data, regulators may have a hard time deciding whether to approve investment proposals and how to hold utilities accountable for their best estimates of costs and benefits.

For example, investments in new distribution technologies, such as those necessary to efficiently and reliably integrate distributed generation or effectively use the wealth of information provided by advanced metering infrastructure (AMI), may be subject to uncertainty about not only the *level* of costs and benefits but also about their timing and achievability. To be most effective, these investments may require coordination across different utility business units and the integration of legacy data communications and information management systems. Utilities may have limited experience with these technologies and have to work closely with equipment vendors that may have little experience with electric power distribution systems. Complicating calculations further, many new technologies have benefit streams that potentially will extend many years after costs have been incurred and are partially a function of future technology innovation and deployment decisions. As a result, modernization investments may not be easily justified by predictable short-term improvements in reliability or incremental improvements in operations or operating costs. Extrapolation or meta-analyses of pilot results may help to narrow the range of likely outcomes, but considerable uncertainty for system deployments may remain.

In addition, state regulators have sometimes approved investments in *ex ante* prudency reviews only to later deny a utility's full cost recovery. For example, a recent Colorado decision denied Xcel Energy cost recovery for certain smart grid investments in Boulder, Colorado, after the regulator had approved the investment proposals, because the costs were substantially in excess of those initially anticipated.[10] While such actions may be needed to provide strong incentives for managing costs, aversion to such risks may make utilities excessively cautious in proposing investments with highly uncertain costs. The political process may create similar conservatism among regulators. Regulators are unlikely to face censure for failing to encourage novel investments that might have yielded new benefits or moderated rate increases but that customers never learn about. In contrast, regulators may face considerable criticism for approving rate increases for technologies that fail to meet expectations or, worse, involve well-publicized problems.

Another challenge posed by the changing nature of new investments is that some significant benefits of grid modernization may not be fully internalized by a single utility or its customers.[11] For instance, if a particular distribution utility increases the responsiveness of its customers' demand or the efficiency of their energy use and thereby reduces regional generation costs, some of the benefits may accrue to customers in the same region who are not served by that distribution utility. Similarly, early adopters of new technologies and systems may end up incurring costs that are avoided in later adoptions through learning spillovers from early experiences.

These considerations may bias investment toward the mature technologies and assets that are familiar to utilities and regulators.[12] Such conservatism may dramatically retard the adoption of technologies to modernize the grid, even when deployment of those technologies is likely to be the most cost-effective path to accommodate the policy goals impressed on the system.

FINDING

Excessively conservative decision-making by utilities and their regulators may dramatically slow cost-effective investments to modernize the grid.

Traditional Rate Structures Distort Incentives

The traditional structure of electricity rates in the U.S. may increasingly impede efficiency objectives over the coming decades. As discussed in Chapter 7, many consumers face rates that often deviate substantially from the incremental costs their consumption decisions impose on the electric power system. Rates charged to most residential and small commercial customers vary little or not at all over the hour or the day, leading to excessive consumption during system peaks and inefficiently discouraging off-peak consumption. Real-time prices that reflect current system costs are rare, even among larger customers.

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If delivered prices are below incremental costs, as may occur during peak demand periods for customers facing time-invariant rates based on average costs, customers will use inefficiently high quantities of electricity at high-cost times. This can increase energy acquisition costs and require additional investments in both generation and grid capacity to meet peak demand, reducing capacity utilization and increasing average costs (and therefore average rates) above efficient levels.

But prices that are higher than incremental costs can be equally distortionary. By recovering a substantial portion of distribution and transmission costs through volumetric charges, the dominant U.S. rate practices give utilities incentives to increase their sales and discourage energy conservation and distributed generation because they reduce sales. Volumetric charges are especially problematic when energy consumption falls. If network costs are largely unchanged by consumption changes, as we would expect, reduced consumption decreases revenue by much more than it decreases costs, creating a revenue adequacy problem for the utility and perhaps setting off a spiral of rising rates. While these problems are not new, they are likely to grow over the coming years as public policies increasingly favor energy efficiency and distributed generation.

On the customer side, when the average delivered price of electricity is higher than the incremental cost of providing that energy, there is an incentive for "disintermediation"—reducing purchases of power from the regulated utility. This situation with respect to wholesale generation costs led many large industrial and commercial customers in states with high regulated rates in the 1990s to press for restructuring and retail competition so they could shift their purchases to lower-cost wholesale providers or self-generate.[13] The coming decades could see a similar phenomenon among smaller commercial and residential customers. High per kWh distribution rates create an implicit subsidy to self-generation of all sorts—solar, wind, or diesel. Renewable generation may receive additional direct subsidies. This could lead to inefficiently high use of self-generation, and there is no reason to assume it will all be "clean." Forty-six states and the District of Columbia use net-metering systems that compensate distributed generation through avoidance of volumetric retail rates[14] even though network-related costs to serve a customer are not likely to fall with their use of distributed generation. This practice in effect adds an extra subsidy to distributed generation not given to grid-scale generators. Inclining block pricing used in some jurisdictions—rates that increase as monthly consumption rises—can exacerbate the problem.[iii] The distortions caused by these implicit subsidies rise with the penetration of distributed generation and with energy conservation more generally. Consider, for example, proposed "zero net energy" buildings: if network costs continue to be recovered on a per-kWh basis, these customers could in theory receive all the benefits of being connected to the grid, drawing and injecting power on demand, while paying little or nothing toward the cost of the system or the option to use the network.

High per kWh distribution rates create an implicit subsidy to self-generation of all sorts.

[iii] Some have suggested that distortions induced by volumetric charges to recover fixed costs and the potentially greater distortions caused by increasing block pricing may be justified by the presence of imperfections in the market for electricity—for example, because cost-based prices do not reflect the incremental social cost of electricity consumption, particularly from "dirty" sources, or because consumers need higher prices to overcome their inertia and make desirable efficiency investments.[15]

While the economic theory of "second-best pricing" recognizes that marginal cost prices may not be optimal in the presence of market and decision-making imperfections, there is no theorem suggesting that one potential distortion merits another. Such decisions must be based on careful analysis and situation-specific modeling and measurement to ensure improvements to welfare, with a healthy skepticism toward the benefits of adding layers of distortions.[16]

FINDING

Net metering policies provide an implicit subsidy to all forms of distributed generation that is not given to grid-scale generators.

Moreover, distributed generation and efficiency programs do not appreciably reduce transmission or distribution system costs—and may even increase them as investments are needed to accommodate more than modest increases in renewable generation. Who pays for the revenue lost because of such programs under current rate structures? If all customers reduce consumption proportionally and fixed system costs are unchanged, in the long run volumetric rates must rise to exactly offset the fall in consumption. The per kWh rate will rise, and customers' total bills after rates adjust will be smaller only by the energy cost differential. If consumers do not understand this when investing in self-generation or efficiency, consistently smaller returns than anticipated from their investments may create substantial dissonance. If only some customers reduce their net energy purchases through self-generation or efficiency investments, distribution system costs will be shifted onto those who do not. This raises questions of both horizontal inequity—treating otherwise similar consumers differently—and vertical inequity—penalizing lower-income consumers, who may be disproportionately represented among those less able to finance investments to reduce net electricity consumption. Requiring middle- or lower-income customers to subsidize wealthier households' investments in energy reduction, as traditional rate structures do, would seem difficult to rationalize on equity or political grounds.

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Rising Rates Stress the Regulatory Process

Rising costs often test regulatory systems. Utility customers, particularly at the residential level, are sensitive to higher nominal bills, as noted in academic work in the mid-1970s and reinforced by the recent backlash against higher monthly bills coincident with AMI rollouts in Texas and California.[17] Customer resistance to higher rates may pressure regulators to avoid increases, even when they are needed to compensate utilities for efficient levels of operating and investment costs.[18] This was not a significant problem over the past two decades, when nominal rate increases were modest and average real prices fell across most electricity markets. But the increased cost of new transmission and distribution investments, combined with possible increases in average generation costs due to policy mandates, such as renewable portfolio standards or more stringent environmental regulations, may lead to significant increases in the delivered cost of electricity. The Electric Power Research Institute (EPRI) estimates the average *incremental* increase in monthly electricity bills required to finance smart grid transmission and distribution investments will be in the range of 8%–12% for residential and commercial customers when amortized over a 10-year period.[19] In the same report, EPRI also notes that digital-based technologies depreciate more quickly than do historic distribution system assets, so maintaining the smart grid system may require higher ongoing investment levels than in recent decades. These expenditures are in addition to rate increases needed to compensate for higher generation costs and investment in transmission and distribution to meet load growth, replace end-of-life assets, and integrate renewables.

Without policy adaptation, the system risks destabilization: If utilities make investments in an environment of substantial uncertain cost recovery, their cost of capital may rise, exacerbating cost-recovery challenges. But if utilities defer investments, they may be unable to meet the conflicting demands of customers, regulators, and policy makers. Finding ways to increase the efficiency of the power system, and therefore reduce costs, will be critical to offsetting some of this pressure. Improved transparency and active customer education and engagement also may help mitigate some customer resistance to necessary rate increases. Communicating the rate implications of new investments and programs poses challenges, however. For example, investments that reduce costs from what they would otherwise have been but still involve rate increases may create substantial dissonance if customers anticipate rate *decreases* that fail to materialize.

The volumetric rate structure for residential and small commercial customers may further reinforce a perverse dynamic over time.

The volumetric rate structure for residential and small commercial customers may further reinforce a perverse dynamic over time. Reduced consumption threatens the ability of a distribution utility to recover its predominantly fixed costs. This, in turn, necessitates rate increases. Higher prices offset the savings customers may have expected from their efficiency or conservation decisions and may provide an even larger incentive for future reductions in customer demand, ratcheting prices up still further. This cycle of rising distribution rates further incites customer dissatisfaction and may distort consumption decisions. While some have argued that increasing efficiency and distributed generation are benefits of volumetric rates, inducing customer-side investments on the basis of illusory bill savings may create considerable political backlash over time, particularly if consumers focus on nominal rates.[20]

A "Franchise Monopoly" Mind-set May Discourage Innovation

While there is broad consensus that physical distribution networks comprise a natural monopoly, there is little agreement that other functions provided by distribution system operators should be assigned exclusively, or at all, to a legal monopolist. Indeed, a primary motivation for electricity restructuring across a number of countries and in many U.S. states was the perceived potential for competition in both wholesale generation and retailing markets to reduce costs, and ultimately electricity rates, from what they would otherwise have been.[21] Under retail competition, consumers receive regulated delivery services from their distribution utility and are free to purchase energy and other related services from competitive electricity retailers.

As Chapter 1 noted, while more than half of U.S. states allow retail competition for large industrial or commercial customers, few today have competitive electricity retail markets at the residential level. In part, this reflects the retrenchment from electricity restructuring efforts that followed the California electricity crisis of 2000–2001.[22] The form of retail competition also varies widely. At the extreme is the fully separated EU model, implemented through its Electricity Directive, in which the distribution utility is allowed to sell only distribution network services; energy and other services must be purchased from other enterprises. This is essentially the approach used in Texas, but retail competition associated with full unbundling constitutes the exception and not the rule in the U.S. Without retail competition, innovation in retail electricity services depends on incumbent monopoly distribution companies. But rate regulation may impede the efficient development and introduction of new services. Innovation involves risk, and as we have noted, regulated firms have little to gain from voluntarily assuming risks: if things go well, the benefits go mainly to customers; if things go badly, the pain is borne mainly by managers and shareholders.

In the presence of new and emerging technologies, competitive entry into retailing may, for example, stimulate the development of new energy management systems, provide investment funds for deployment of new customer premises technologies, leverage retailing efficiencies by facilitating operations across many distribution systems, and provide a better match for the expertise and talent required to be successful in services that rely heavily on information technology and customer engagement activities. Separating retailing from distribution services also could resolve debates over who owns and pays for customer premises demand management technologies and whether the cost of those investments should be "socialized" across all customers through inclusion in a utility's rate base, by shifting those responsibilities onto competing retailers.[iv]

8.3 HOW SHOULD POLICY RESPOND?

Challenges to regulatory policy are gaining increased prominence with the quickening pace of innovation in distribution system technologies, penetration of distributed generation and electric vehicles, and policy emphasis on energy efficiency and alternatives to conventional generation sources. Addressing these challenges in a cost-effective manner is likely to require more widespread use of new regulatory tools, significant adaptation of regulatory processes, and continued experimentation. This section discusses a set of the most promising regulatory responses.

Regulators around the world have shifted regulation of traditional "public utility" sectors ... from cost-of-service to incentive-based schemes designed to motivate utilities to reduce operational costs without sacrificing reliability or quality of service.

Enhance Performance-Based Incentive Regulation

Regulators around the world have shifted regulation of traditional "public utility" sectors—for example, local wireline telecommunications, natural gas distribution, and distribution of electricity—from cost-of-service to incentive-based schemes designed to motivate utilities to reduce operational costs without sacrificing reliability or quality of service. Inherent in their design is the possibility that utility revenues may exceed or fall short of costs for significant periods of time. The potential savings from these approaches may be considerable. For example, electricity distribution companies in England and Wales that were subject to price cap regulation dramatically reduced operating costs, reflecting the combined benefit of incentive regulation and privatization.[23] While the use of incentive-based regulation in U.S. electric utilities has been more limited, empirical analysis of restructured U.S. electricity markets reveals improvements in generator efficiency associated with some forms of regulatory incentives and with market-based competition among generators instead of cost-of-service regulated rates.[24]

[iv] Regulators cannot ignore, however, that the main business of retailers is to sell electricity. When energy efficiency and savings becomes a regulatory priority, energy service companies, whose only purpose is to reduce consumption or to shift it to low cost periods of time, are best suited for this job.

Internationally, the most common form of incentive-based regulation sets a price or total revenue cap for delivery service that is fixed over a given time period, typically three to five years, and is thus independent of actual costs. During this period, firms are allowed to charge prices (or earn total revenues) that increase with an index of the general price level, plus or minus a fixed percentage adjustment factor set by the regulator. The adjustment factor is generally set to equate the discounted expected values of costs and revenues over the time period considered, taking into account expected productivity gains. This approach, pioneered in England and Wales, generally is known as RPI – X regulation, where RPI refers to the Retail Price Index (like the U.S. Consumer Price Index), and X is the adjustment factor determined by the regulator. Under this system, regulated firms can increase profits by reducing costs relative to the index.

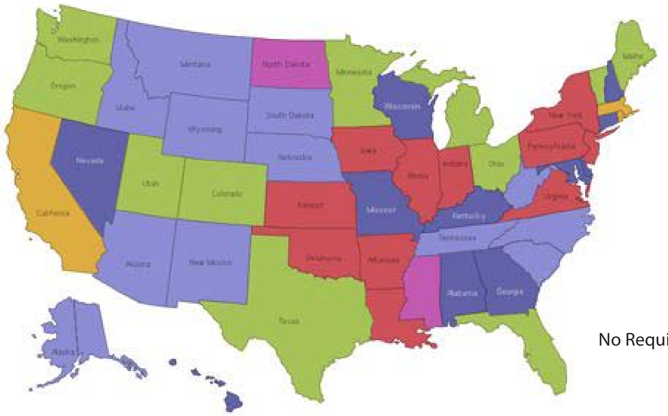
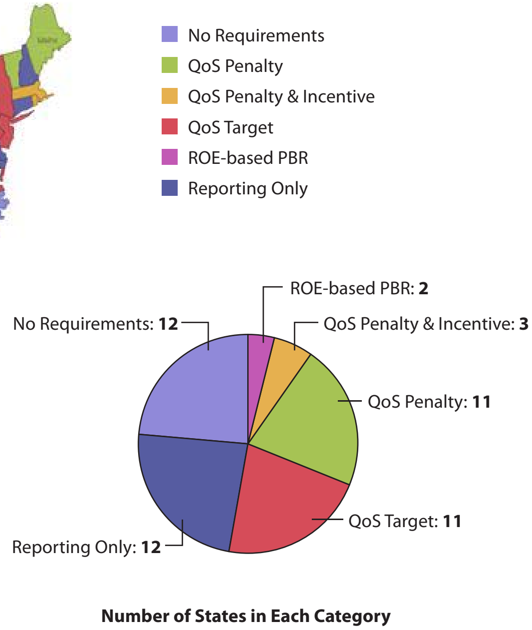
Since one way of reducing costs may be to reduce spending on reliability or service quality, implementations in England, Australia, and other countries in Europe and Latin America have evolved to include performance metrics and assign penalties or rewards depending on whether utilities meet these predetermined targets. During the 1990s, regulators in many U.S. states began experimenting with a variety of incentive-based regulations. These included a broad range of changes, from relatively short-term price caps, to rate freezes, rate case moratoria, and earnings sharing plans. In 2001, at least 28 distribution utilities in 16 states were regulated under such mechanisms.[25] Subsequently a number have returned to more traditional cost-of-service-based ratemaking supplemented by reliability or quality-of-service targets with penalties and rewards as performance incentives.

As of 2005, 16 states had a form of performance-based regulation that included explicit penalties or rewards based on performance in reliability and/or quality of service.

Figure 8.1 classifies U.S. states based on their adoption of performance-based regulatory systems involving quality of service. As of 2005, 16 states had a form of performance-based regulation that included explicit penalties or rewards based on performance in reliability and/or quality of service.[26] Of these, two states adjusted the allowed rate of return based on performance. An additional 23 states set service targets or required utilities to report performance but associated no financial consequences to those reports. Assessing the impact of performance-based regulation across U.S. distribution utilities is extremely difficult, in part because of this heterogeneity in standards, incentives, and performance reporting. One study finds programs that provide generating units incentives to meet certain heat rate and availability goals are associated with improvements in generating unit efficiency, suggesting at least some role for performance-based incentives.[27]

Jurisdictions that require electric utilities to report performance on various metrics have commonly used the results to provide incentives for efficient operations. While less high-powered than the price or revenue caps many European systems employ, performance-based incentives may yield some gains even at the level currently employed across many U.S. utilities. Expanding their use and formally tying performance to financial incentives can increase those gains, particularly as regulators and utilities are faced with assessment of new technologies. Candidates for measurement and reporting would include detailed information on the duration, incidence, and cause of outages; customer service indicators; power quality measurement; and performance on possible policy goals, such as integration of distributed generation and electric vehicles or demand response.

Figure 8.1 States with Performance-Based Cost-of-Service Regulation, 2005

Definitions

Return-on-equity-based Performance-based Regulation (ROE-based PBR) – rate of return is set with a dead band (range the utility and shareholders assume all benefits and cost) and a live band (range above and below the dead band that would have a sharing mechanism assigned)

Quality of Service (QoS) – rate of return is set by using the conventional cost of service methodology and the utility has reliability and/or quality of service targets set by the commission with either a **penalty & reward incentive**, **penalty only**, or **target only** (neither penalty nor reward)

Reporting Only – utility is required to report performance with no penalty, reward or target

Source: Davies Consulting, Inc., *State of Distribution Reliability Regulation in the United States* (Washington, DC: Edison Electric Institute, 2005), Table 4-1.

FINDING

Greater performance-based regulation can improve the efficiency of the distribution system and the quality of utility investments. Better and more comparable data on system costs and performance, including how well the system accommodates policy goals, are needed for its effective implementation.

The value of cost and performance data could be substantially enhanced by coordinating the definition and measurement of metrics across regulatory jurisdictions, expanding their use in regulation, and publishing data on observed performance. While heterogeneity across service territories may preclude simple formulaic comparisons across utilities, commonly publicized metrics could support incentives for improvement and facilitate the development of standards of service. Progress along these directions should be strongly encouraged.

Regulators in the European Union and elsewhere use two tools—benchmarking and reference network models (RNMs)—that can further enhance the value of incentive-based regulation. Benchmarking involves gathering and analyzing comparable cost and network data from a large number of potentially similar utilities.[28] Regulators outside the U.S. commonly benchmark operating costs and quality of service across different types of networks to determine efficient cost and performance levels for comparable utilities.[29] For prices set using RPI – X formulas, this exercise can help regulators understand the significant cost drivers external to the utility and thus choose a price or revenue cap and adjustment factor that satisfies expected cost-recovery goals. As might be expected, the most cost-efficient utilities do not always exhibit high levels of service quality.[30] By focusing both on service quality and costs, regulators can attempt to provide utilities with incentives to reduce operating cost while maintaining acceptable levels of service quality.

Gaps in publicly available, detailed, utility-specific data—particularly on performance—for a large number of U.S. distribution utilities currently make it difficult to use benchmarking methods.

Hindering benchmarking efforts are differences in the size and geographical dispersion of the customer base; terrain of the service area; design choices of underground or overhead lines; age and type of assets; amount and timing of specific investments; and accounting or depreciation practices across jurisdictions.[31] Although econometric models combined with detailed system data may help regulators to expand the set of firms deemed "comparable," it can be difficult to adjust for these and other differences, particularly for capital investments. Even in jurisdictions that employ price caps with RPI – X indices for operating costs, capital costs tend to be incorporated into price caps in a manner quite similar to cost-of-service reviews.[32] But by incorporating lessons from others' experiences, benchmarking may at least reduce the significant uncertainties associated with investments in some new technologies.

Gaps in publicly available, detailed, utility-specific data—particularly on performance—for a large number of U.S. distribution utilities currently make it difficult to use benchmarking methods. With distribution network modernization proceeding at different rates across the nation, data will need to be collected over a long period to inform comparisons of modernized distribution systems. The earlier and more intentional the data collection and analysis are, the more informative the results of benchmarking are likely to be.

A second tool used by distribution system regulators in a number of European countries is an engineering-based RNM. These models accept detailed data on the geographical terrain of an individual utility's distribution service area, its network design, and customers' position and load profiles to provide a customized reference or benchmark against which its realized operating and investment performance can be evaluated.[33] By incorporating technical and reliability constraints, distribution network configurations, and operation and management costs, RNMs permit simulation of investment and revenue requirements. RNMs thus can be used to assess capital and operating expenses not only in the design of new distribution systems but also in the expansion of existing systems. They also may be helpful in estimating costs of nontraditional investments for integrating distributed generation and accommodating electric vehicles, and they may improve our understanding of how these new network users affect reliability and quality of service.

A disadvantage of RNMs is that they are necessarily complex and difficult to understand for those not expert in planning distribution networks. An integrated assessment of the wide range of technologies under consideration is needed to build models that can accurately represent evolving distribution systems. However, once built and validated, an RNM can be shared across jurisdictions to provide regulators with both qualitative and quantitative insights into the impacts of potential system changes. The model can complement regulatory judgment in assessing the impact of new policies and informing the design of targeted experiments or pilot projects.[34]

Create New Cost-Recovery Paradigms

Addressing the increased uncertainty inherent in many new grid technologies will require regulators and utilities to consider new cost-recovery regimes. Traditional utility regulation has focused more on curbing monopoly power and avoiding excessive costs and less on encouraging innovation. This focus is becoming increasingly expensive, as technological change is rapid and the potential gains from innovation are great.

A core determinant of innovation incentives is the allocation of and compensation for investment risk. On the one hand, if investor-owned utilities do not expect to earn at least their cost of capital on new investments unless everything goes exactly as planned, they will avoid investments with any risk, and the promised benefits of new technologies will be realized too slowly or perhaps not at all. On the other hand, ensuring utilities full cost recovery regardless of the level of incurred costs or realized benefits would give them little reason to contain costs or carefully vet investment proposals. Consumers in the latter case might see significant innovation but could face substantially higher costs and excessive risks. The difficulty is finding a good middle ground between these extremes.

For non-investor-owned utilities, versions of this trade-off arise that involve rewards and penalties for utility managers and their supervisors depending on the outcomes of risky investments. Some have suggested to us that these utilities may be more willing to innovate because managers do not have to worry about shareholder reactions to bad outcomes. While some economic analyses suggest scope for substantial managerial discretion in publicly owned entities,[35] we are unaware of any definitive evidence on the empirical relation between utility governance structure and incentives for innovation.[v]

Variants of traditional ratemaking approaches may partially address the challenges risky investments pose. Pilot projects have been funded by ratepayers to demonstrate both feasibility and assess costs through a small-scale deployment. Reversing the decline in utility R&D budgets noted in Chapter 1 to restore modest funding may help fund experimental deployments, which typically require collaboration between utilities and vendors; leveraging R&D budgets through more cross-utility R&D projects or industry organizations, such as EPRI, may enhance their impact. Regulators could reduce utilities' risks by conducting an *ex ante* prudency review as part of a forward-looking planning process—perhaps using RNMs or benchmarking—and authorizing investment expenditures up to a specific ceiling based on that review. This reduces risk when investments within a predefined range of those expenditures are then exempt from *ex post* reconsideration, or when cost recovery is conditioned on achieving specific predetermined functionalities. Some jurisdictions address short-run uncertainty in cost recovery through the use of trackers or balancing accounts. These mechanisms follow a specific

Addressing the increased uncertainty inherent in many new grid technologies will require regulators and utilities to consider new cost-recovery regimes.

[v] One suggestive piece of evidence is that cooperatives have deployed AMI to almost 25% of their customers, and "political subdivisions" (public power districts, public utility districts, and the like) have deployed it to more than 20%. In contrast, only 6.6% of IOU customers have AMI, and penetration is even lower for municipal entities (3.6%) and federal and state utilities (0.7%).[36] Clearly these dramatic differences reflect more than governance. In particular, cooperatives and political subdivisions tend to have more geographically dispersed customers, which implies larger benefits from AMI communication capabilities. But the differences are so large that it is hard to believe that governance is not part of the story.

type of expenditure—for example, AMI deployment costs—over a specified period and increase rates or add a surcharge over a number of subsequent periods until the full cost has been recovered. Regulators also have authorized recovery of some risk-contingency funding at the beginning of an investment project or rewarded utilities with incentive payments above and beyond their investment costs for meeting or exceeding specified performance targets.

While approaches such as these may reduce utilities' perceived investment risk, they do not necessarily provide strong incentives to minimize costs. Cost-sharing or shared savings plans can contribute to that goal. For example, the California Public Utility Commission authorized a cost-sharing plan for San Diego Gas & Electric's AMI deployment that rewarded utility investors with a share of savings if investment costs fell below authorized levels, but required investors to bear a share of cost overruns. Programs that penalize utilities if they do not attain certain levels of forecast benefits from investments are another way regulators may attempt to strengthen incentives for cost-efficient investments.

FINDING

Innovative network technologies may require new regulatory approaches to encourage experimentation and efficient deployment, especially when their costs are uncertain and their benefits involve enhancing the performance of the transmission or distribution system rather than merely expanding its capacity.

Creative regulatory approaches may be particularly valuable by promoting investments in the most innovative technologies, where costs and benefits are most uncertain. Collaborations among regulators, utilities, and technology providers are likely to be important in this domain. Experimental policies in the United Kingdom and elsewhere may yield insights for state regulators and others who supervise distribution utilities. For example, the U.K. Office of Gas and Electricity Markets has proposed a set of new cost-recovery, stimulus, and competition programs to encourage investment in promising but uncertain new network technologies.[37] These programs are intended to reduce asymmetries between risk and reward for investments in new technologies, provide a source of financing, and employ potential competition to encourage experimentation and deployment.

The three main IOUs in California, in collaboration with the Lawrence Livermore National Laboratory, recently proposed a novel approach to encourage innovation in a joint filing to the California Public Utility Commission.[38] The California Energy Systems for the 21st Century Project requests a five-year $150 million commitment from ratepayers to fund R&D relating to four broad areas: cybersecurity, electric resource planning, system operations, and workforce preparedness. Specific selection of activities and oversight will be provided by a board of directors that includes representation from industry, government, and, potentially, public interests. The project emphasizes the development of planning tools and system integration, areas that are likely to be increasingly important for distribution systems. The regulatory response to this proposal as well as its potential implementation and ultimate output may provide a model for other jurisdictions.

The problem of providing appropriate incentives for investment in innovative distribution system technologies is difficult. But it is important now and will become more important in the decades ahead. State regulators and others who supervise distribution utilities should tackle it sooner rather than later. The diversity across U.S. jurisdictions in regulatory philosophies and approaches could be a source of strength, as long as regulators maintain transparency and exchange experiences to identify and emulate the most promising solutions.

Improve Rate Structures

Utility rate structures will assume increased importance going forward, particularly as potentially large investments in transmission and distribution systems cause rates to increase and threaten the current political equilibrium. As noted earlier in the chapter, transmission and distribution costs are largely independent of delivered energy in the short term, but the recovery of those costs from residential and small commercial customers generally is heavily dependent on energy sales. Whenever prices are out of line with costs, behavior is distorted and economic efficiency is reduced.[vi]

FINDING

Recovery of largely fixed network costs through volumetric ($/kWh) charges distorts the behavior of utilities, their customers, and investors in distributed generation—and may be politically unstable in an era of rising costs.

Reducing reliance on energy sales for transmission and distribution network cost recovery addresses these problems directly. Regulators can accomplish this by increasing fixed customer charges or demand charges (charges that depend on peak kW or capacity use, not energy use) and reducing or eliminating per kWh charges for network cost recovery.[vii] Not only does this approach remove the root cause of distortions while assuring recovery of approved costs, it also may be more politically sustainable over time than are volumetric charges.

In the past, recovering costs through volumetric charges for smaller customers may have been expedient: network charges were not a large fraction of the total electricity bill, and metering costs to compute appropriate demand charges were relatively high. Less costly alternatives used outside the U.S., such as limiters that prevent consumption levels above a contracted peak amount, had little appeal to U.S. regulators. As network charges now approach parity with energy costs for many customers, this structure demands closer attention. And as AMI diffuses, it becomes easier and less expensive to vary fixed charges across customers in ways that reflect their differential impacts on the need for network development.

AMI meters can record consumption that is coincident with system peaks or measure average consumption over a set of designated peak hours. These facilitate a transition to fixed monthly delivery charges that vary with either usage in local peak periods or another measure of impact on the need for network capacity. Because peak usage tends to be correlated with total usage across households, these charges will lead to "larger" customers generally paying a greater fraction of system costs than do "smaller" customers, as they do under volumetric pricing, but without

[vi] In principle this problem also arises with regard to transmission costs in most areas, and both transmission and distribution charges should be addressed similarly. However, because transmission costs are considerably lower than distribution costs, the distortions caused by recovering fixed transmission costs via volumetric charges may be less severe.

[vii] An ideal approach would start with energy charges based on locational marginal prices at each distribution node and point in time, and use customer fixed charges to recover more of the remaining network costs. But current systems are far from measuring, let alone implementing that ideal.

substantial distortions to consumption and distributed generation investment decisions. Moving from volumetric to peak-demand-based cost recovery also largely eliminates any utility incentive to increase its sales. And fixed pricing may better match costs to revenues: given that distribution system capacity heavily depends on the local peak demand, demand charges better reflect the capacity costs each customer imposes on the system. Reduced demand at system peaks can lead to lower distribution costs over time by reducing the need to replace or add distribution capacity, which is not the case for reductions in energy usage during most periods.

Where regulators choose not to place primary reliance on demand or fixed customer charges,"decoupling" mechanisms can address some of the problems the volumetric rate structure creates. Decoupling mechanisms aim to separate utilities' revenues from their volumetric sales, improving recovery of fixed delivery costs between rate cases and thereby mitigating utilities' incentives to maintain or increase energy sales. If all distribution costs were recovered through fixed charges, a utility's revenue would be independent of its sales in each period—essentially perfect decoupling. The greater the share of distribution costs recovered through volumetric charges, the more need there may be for formal decoupling programs.

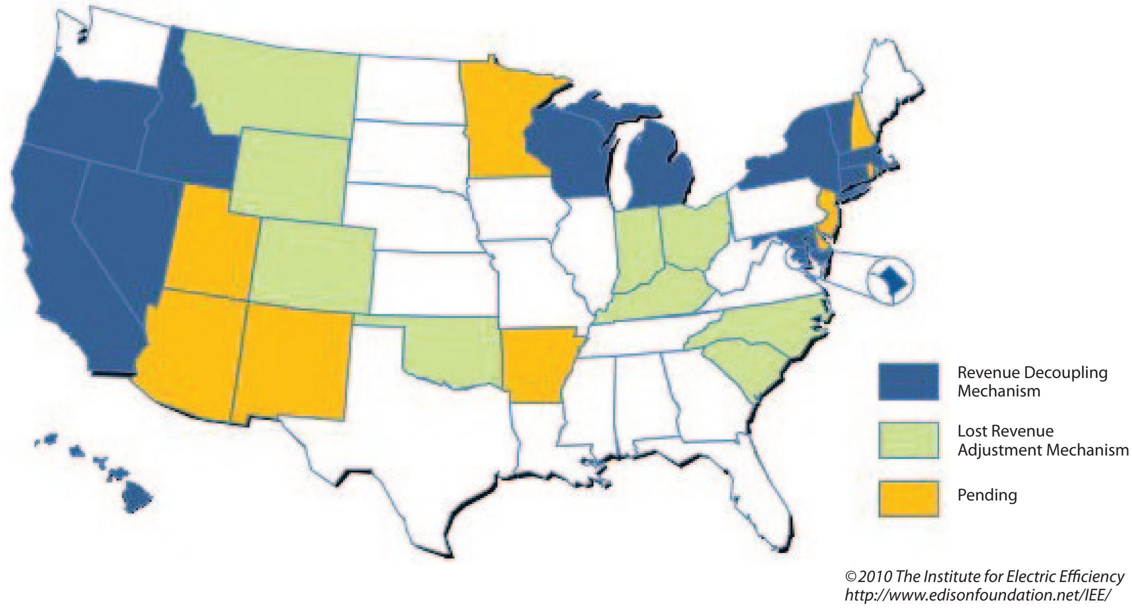
Popular forms of decoupling in the U.S. include revenue caps and revenue-per-customer caps. In a revenue cap system, the utility is assured of full recovery of a regulator-determined level of revenue over some period. At the outset, that total revenue is divided by expected sales (total kWh) to get a $/kWh rate. When actual sales deviate from expected sales, as they inevitably will, the volumetric rate is adjusted to meet the revenue requirement for the following period. In the revenue-per-customer approach, system costs are assumed to vary directly with the number of customers served by the utility company. Thus, the revenue cap is divided by the number of customers; rates are subsequently adjusted to reflect changes in the number of customers as well as to "true-up" for deviations of actual sales from expected sales.

As an alternative to decoupling, some states have adopted "lost revenue adjustment" mechanisms, which generally compensate utilities only for net revenue losses imputed to utility-based energy conservation programs. These partial programs do nothing to address customer-initiated changes in usage independent of those programs, however.

As of June 2011, 12 states and the District of Columbia had decoupling mechanisms, as illustrated in Figure 8.2. An additional nine states had lost revenue adjustment mechanisms. Another nine states were in the midst of proceedings to decide whether to implement decoupling.

Advocates of energy conservation are some of the strongest proponents of decoupling and describe its essential purpose as "reduc[ing] a utility's disincentive to promote energy efficiency" (for example, see Minnesota statute 216B.2412).[39] While decoupling does not provide the utility with incentives *for* conservation, it may help mitigate conflicts between the distribution utility's need for cost recovery and the policy goal of reduced electricity consumption, by eliminating incentives to maximize energy sales. Its impacts on cost recovery and effectiveness depend on the details of its implementation, which vary across systems. Decoupling does nothing to address the shift of transmission and distribution system costs from customers who are reducing their consumption through efficiency or distributed generation investments onto the remaining system customers.

Figure 8.2 U.S. States with Decoupling and Lost Revenue Adjustment Mechanisms, 2011



Source: Institute for Electric Efficiency, "State Electric Efficiency Regulatory Frameworks" (Washington, DC, 2011).

Reliance on volumetric cost recovery may be particularly problematic when installations of distributed generation are subject to net metering. Under net metering, a kWh of generated electricity reduces a customer's bill not only by the avoided energy cost but also by the amount of the delivery service charge. The greater the quantity of electricity generated onsite, the less a customer contributes to cover the grid's cost. As discussed earlier, this implicit subsidy to distributed generation may reduce utility revenue in the short run if rates are not decoupled and will shift the burden of network costs to customers without (clean or dirty) distributed generation. This problem is more serious, all else equal, the greater the fraction of network costs that are recovered through volumetric charges and the less correlated a customer's peak net demand is with their total (gross) consumption of electricity. Similar distortions may arise for investments in energy efficiency or conservation under volumetric rate structures.

Reliance on volumetric cost recovery may be particularly problematic when installations of distributed generation are subject to net metering.

8.4 CONCLUSIONS AND RECOMMENDATIONS

Upward pressure on electricity rates will increase the value of more efficient transmission and distribution operations, and customer concerns with reliability and other dimensions of performance are likely to increase over time. Collecting and publishing comparable data on utilities' costs and service quality can help regulators evaluate and reward good, efficient performance.

RECOMMENDATION

Utility outcomes should be tied to performance metrics that allow for comparisons across utilities and over time. State regulators and others in charge of supervising utilities should develop and publish a consistent set of cost and performance metrics that allow these comparisons.

Performance measures should include progress on any policy goals imposed on distribution systems, as well as more traditional system quality and cost measures. These policy goals may include accommodation of distributed generation and electric vehicles, penetration of dynamic pricing, and distribution automation. If measurement is to have an impact, the results should be made public, and regulators should provide explicit incentives for good performance.

Traditional utility regulation has focused more on curbing monopoly power and avoiding excessive costs than on encouraging innovation. This emphasis is becoming increasingly expensive in an environment with rapid technological change and consequent potential for significant efficiency gains.

RECOMMENDATION

State regulators and others in charge of setting utility rates should design mechanisms for risk allocation and compensation to balance incentives for innovative, risky investment with efficiency gains and ensure that the results of innovative investments are shared with customers.

We endorse no specific mechanism. This is a hard problem that calls for creative experimentation, greater collaboration, and sharing of best practices across jurisdictions.

Recovery of fixed costs through volumetric rates ($/kWh) distorts the behavior of utilities and their customers. As distributed generation and efficiency investments become more widespread, the value of mitigating these distortions increases.

RECOMMENDATION

State regulators and those who supervise government-owned and cooperative utilities should recover fixed transmission and distribution network costs primarily through customer-level fixed charges, which may differ across customers but should not depend on energy (kWh) usage.

Fixed charges should vary with the extent to which customers contribute to the need for network development. This need might be approximated by past demand in peak periods or estimated by demand profiles. In systems that continue to rely significantly on volumetric charges for the recovery of network costs, utility incentives to increase sales can be blunted by decoupling utility revenues from short-run changes in quantities sold.

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Chapter 9: Data Communications, Cybersecurity, and Information Privacy

In this chapter, we discuss the opportunities associated with expanded data communications capabilities throughout the electric grid and the related cybersecurity and information privacy challenges.

Section 9.1 describes the evolution of grid communications systems and discusses the interoperability and network ownership challenges posed by expanded communications. Data communications will increasingly link the various components of the grid, from generator to transmission line to substation to distribution network to consumer meter, and to equipment and appliances within homes and businesses. As communications needs and technologies continue to change, the industry will have to deal with a state of "continuous transition" unlike anything it has seen before. This discussion serves as important background for our recommendations related to cybersecurity and information privacy.

Section 9.2 is an examination of cybersecurity issues facing networked grid systems and related regulatory developments. Ongoing cybersecurity standards development processes are critical to securing the grid. However, it will be impossible to fully protect the grid from cyber accident or attack, and response and recovery mechanisms that reduce the impact of these events need to be investigated and promulgated throughout the industry. While the North American Electric Reliability Corporation has developed Cybersecurity Infrastructure Protection standards covering the bulk power system, and the National Institute of Standards and Technology is coordinating the development of a standards framework across a large group of industry, academic, and government participants, no organization currently has responsibility for overseeing grid cybersecurity across all aspects of grid operations.

In Section 9.3 we examine the information privacy issues related to expanded operational and consumer data collection, storage, use, and disclosure. Consumers have raised these issues and state PUCs are responding by creating various regulations regarding the protection and use of consumer electric usage data (CEUD). With companies working in multiple states and data crossing state boundaries, further coordination among these agencies will be needed to ensure the public that data collection in the future grid is appropriately protected.

We conclude, in Section 9.4, with a set of recommendations. We highlight the importance of existing industry-government partnerships that are working towards establishing comprehensive interoperability standards. We also recommend the designation of a single agency with responsibility for cybersecurity preparedness, response, and recovery throughout the entire grid. Finally, we recommend that state agencies and other stakeholders focus on coordinating their efforts related to data privacy.

The electric grid is a "system of systems," managed by thousands of people, computers and manual controls, with data supplied by tens of thousands of sensors connected by a wide variety of communications networks. Over the next 20 years, the growth in percentage terms of data flowing through grid communications networks will far exceed the growth of electricity flowing through the grid. Many advances discussed in this study—from integration of variable energy resources to wide-area situational awareness and real-time control to demand response—result from or depend on this increase in data collection and communications.

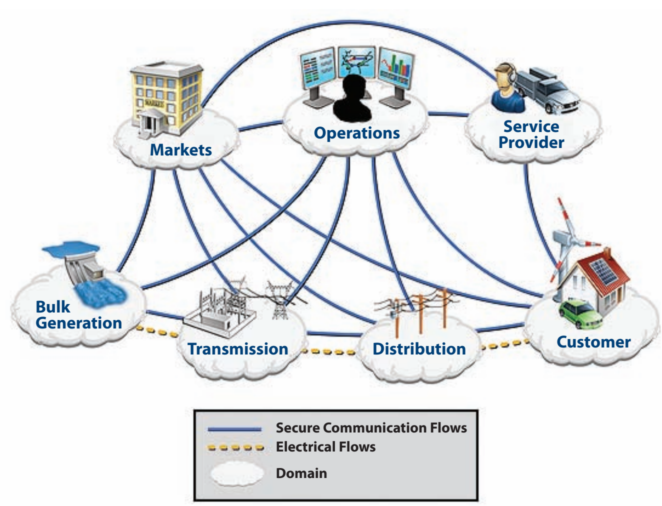
Critical challenges will arise from the expansion of existing communications flows and the introduction of new ones, some of which are illustrated in Figure 9.1.

While the increase in data communications will bring significant benefits, it also will give rise to new costs and challenges. Beyond the direct costs of hardware, software, networks, and staff, significant additional costs may arise from the improper or illegal use of data and communications. Unfortunately, these costs are difficult to quantify and can only be discussed in terms of probabilities and estimates of potential impact to businesses and consumers, complicating the cost–benefit analysis of spending to protect communications systems.

The highly interconnected grid communications networks of the future will have vulnerabilities that may not be present in today's grid.

In addition, the highly interconnected grid communications networks of the future will have vulnerabilities that may not be present in today's grid. Millions of new communicating electronic devices, from automated meters to synchrophasors, will introduce attack vectors—paths that attackers can use to gain access to computer systems or other communicating equipment—that increase the risk of intentional and accidental communications disruptions.[1] As the North American Electric Reliability Corporation (NERC) notes, these disruptions can result in a range of failures, including loss of control over grid devices, loss of communications between grid entities or control centers, or blackouts.[2]

Figure 9.1 Diagram of the Future Electric Grid, Showing Communications and Power Flows



Source: National Institute for Standards and Technology, *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0*, special publication 1108 (Washington, DC: U.S. Department of Commerce, 2010), 33, http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

Making sound decisions regarding cybersecurity, from attack prevention, response, and recovery to information privacy, requires confronting a number of very basic societal and economic questions. As listed in a report by NERC and the U.S. Department of Energy (DOE),[3] these include:

- How much risk is the private sector willing to accept?
- How much risk is the public sector willing to accept?
- How much are consumers (or society at large) willing to pay to reduce this risk?
- Who makes the determination of society's tolerance for risk and the cost of employing protections?
- How should the costs of employing protections be paid for?
- How is damage measured: cost to replace damaged equipment, number of people-hours without power, number of other critical infrastructure nodes affected?
- Where are interdependencies most critical?

To contribute to this discussion, this chapter examines critical topics and strategies to increase awareness and resolution of cybersecurity and information privacy issues in the future electric grid.

9.1 GRID DATA COMMUNICATIONS

Several types of data communications networks already serve many purposes in the electric grid:

- **Utility-owned wide-area and field-area networks** send and receive operational measurement and control signals between control centers, substations, and sensors along transmission lines and the distribution network. They rely on wired (fiber and copper), wireless (cellular), and radio-frequency or microwave communications.
- **Commercial wide-area, field-area, and local (neighborhood) networks** are used for similar purposes to utility-owned networks as well as for communications among corporate data centers. They rely on wired, wireless, radio-frequency or microwave, and power line carrier communications, provided under contract or operating arrangements from common public telecommunications service providers.
- **Public communications networks**, such as the telephone network and the Internet, transmit information, such as pricing signals and daily generation schedules, and communicate with home energy networks.
- **Satellite communications networks** are used where microwave communication is prohibitively expensive; phasor measurement units (PMUs) also use the GPS satellite navigation system to synchronize timing.
- **Home and commercial premises networks** connect appliances and transmit control information from utilities to homes or businesses and are typically provided by the customer.

Table 9.1 illustrates the growing use of data communications in the grid and lists the changes that have occurred in network architectures, media, and protocols over the past 25 years. These changes follow the general evolution of computer and communication technologies and can be expected to continue far into the future. Ensuring that grid communications networks are accurate, reliable, and economical in this constantly changing environment is one challenge to achieving the goals of the future electric grid.

Future Data Communications Architecture

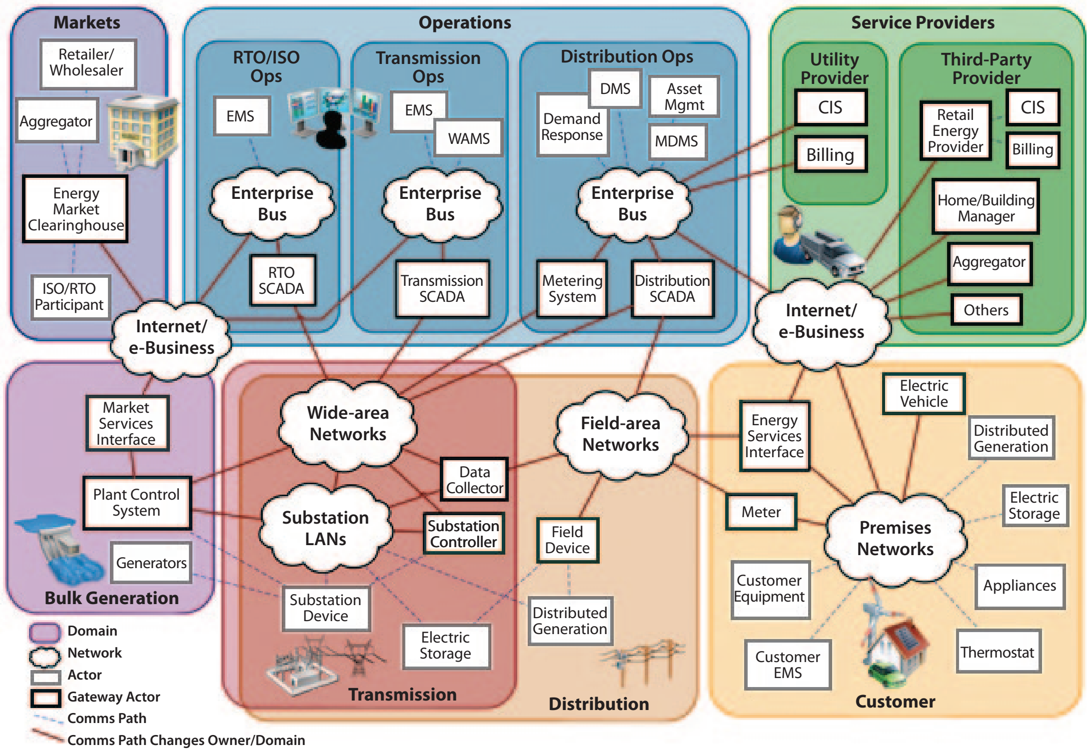
Research projects investigating the future architecture of data communications networks highlight that they will closely link generators, transmission networks, substations, local data collectors, smart meters and appliances, and other grid components using two-way and broadcast communications.[4] In addition, market operators, corporate offices, utility back-office systems, and utility planning systems will be connected with a more flexible, more reliable, and faster communications infrastructure. Figure 9.2 is a conceptual representation of the future of interconnected communications across the electric grid.

Table 9.1 Summary of Communications System Development for Electric Utilities

Phase	Years	System Characteristics	Network Architecture	Communication Media	Communication Protocols and Standards
Nonstandardized	Up to 1985	• Many proprietary systems • Single vendor per system • Basic data collection	• Hierarchical tree • Single master • Isolated substations	• RS232 and RS485 • Dial up • Trunked radio • Power line carrier • Less than 1,200 bytes per second (bps)	• Modbus • SEL • WISP • Conitel 2020
Standards Development Begins	1985–1995	• Multivendor systems • Protocol conversion	• Hierarchical tree • Multiple masters • Redundant links	• Leased lines • Packet radio • 9,600 to 19,200 bps	• DNP3 Serial • IEC 60870 • TASE 2
Local-area Networks (LANs) and Wide-area Networks (WANs)	1995–2000	• Introduction of LANs in substations • Merging protection and SCADA networks	• Peer-to-peer communication in substation • Joining substations via WAN	• Ethernet • Spread spectrum radio • Frame relay • Megabit data rates	• TCP-IP • FTP • Telnet • HTTP • DNP3 WAN/LAN • UCA 2.0
Integration into Business	2000–present	• Merging automation and business networks • Corporate IT departments • Asset management	• Linking of utility WAN to corporate network • Extension of network to customer premises • Use of Internet	• Digital cellular • IP radios • Wireless ethernet • Gigabit backbones	• TCP-IP • IEC 61850 • XML

Source: V. C. Gungor and F. C. Lambert, "A Survey on Communication Networks for Electric System Automation," *Computer Networks* 50, 7 (2006): 877–97.

Figure 9.2 Detailed Communications Flows in the Future Electric Grid



Source: National Institute for Standards and Technology, *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0*, special publication 1108 (Washington, DC: U.S. Department of Commerce, 2010), 35, http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

Note: ISO/RTO = independent system operator/regional transmission organization; EMS = energy management sytstem SCADA = supervisory control and data acquisition; WAMS = wide-area management system; DMS = distribution management system; MDMS = meter data management system; CIS = customer information system; LAN = local-area network.

An important issue in the management and regulation of grid data communications systems will be the blurring of distinctions between "generators" and "consumers," particularly as consumers who previously only consumed electricity begin participating in demand response programs and generating their own electricity through fuel cells, wind turbines, solar roofs, and the like. Data communications systems will need to enable customers to perform these multiple roles. As the grid evolves, the existing point-to-point and one-way communications networks will need to be expanded or replaced with networks designed for two-way communication.[5]

Existing point-to-point and one-way communications networks will need to be expanded or replaced with networks designed for two-way communication.

Data Communications Technologies and Applications

The new grid technologies discussed in this study will generate large amounts of data very rapidly, which will necessitate data communications networks with increased capacity, reduced latency (delay in transmitting and receiving), and higher reliability than is required today. A 2007 National Energy Technology Laboratory report for the DOE recognized these increased needs, finding that "the communications systems utilized in the power industry today are too slow and localized to support the integrated communications needed to enable the modern power grid."[6] Better data storage and management, and more systems to process and use the data, also are needed. Managing diverse computer and communications technologies will pose technical challenges for utility engineers and policy challenges for regulators.

Table 9.2 lists data and network requirements associated with various grid applications. These estimates are from industry sources and include subjective and objective measures. While valuable in providing an overall picture of communications needs, they must be examined carefully for any specific use. Consider the example of reliability requirements, which range from 99% (3.65 days of outage per year) to 99.9999% (31 seconds per year). Not only are these ranges considerable, but they do not show the impact over long or short time periods. A single three-day outage of an advanced metering infrastructure (AMI) system during a hot summer month could eliminate the entire value of a demand response system, whereas multiple short outages in other seasons totaling three days might have little impact. Data rate and latency estimates also have relatively broad ranges. In general, all these estimates show the need for significant expansion and improvement in data communications capabilities.

Individual home networks, which monitor and control appliances and HVAC, have the least stringent requirements, and these networks will most likely be provided by consumers rather than utilities. The bandwidth requirements for AMI data communications are also relatively low at the source—tens of kilobytes per second for individual meters to 100 kilobytes per second for concentrators and access control points. In the aggregate, AMI systems can generate in the range of 1 gigabyte of data per day per million meters, or as much as 1–2 terabytes per year for a major utility, a significant but not overwhelming amount of data. Whether AMI systems transmit even more data in the future will depend on the requirements of demand response and other future applications.

On the other hand, wide-area monitoring systems for more advanced control of the distribution and transmission grids will collect operational parameters—for example, voltage, current, phase, and frequency—at a subsecond rate and transmit these data to grid operation centers for immediate processing and action. These systems will require high data transfer rates with high reliability as well as backup power and other redundancies.

Designing future grid communication networks to meet these network requirements will take creative technical solutions and collaboration among utilities, vendors, systems integrators, and customers. The industry already is working to explore many different system design trade-offs. Most of these decisions will not require direct government input. However, policy makers can make important contributions to two areas of significant debate: standards and interoperability, and ownership of data communications networks. These challenges are discussed in the next two sections.

Table 9.2 Current and Potential Grid Communications Use

Application	Media	Standard/ Protocol	Network Requirements					
			Expected Data Rate/Bandwidth[a]	Acceptable Latency[a]	Frequency of Use[b]	Reliability Need[a]	Security Need[a]	Backup Power[a]
Home-area Network	Power line communications;[c] wireless	HomePlug, ZigBee, IP						
Advanced Metering Infrastructure (AMI)*	Power line communications,[c,d] wireless radio frequency,[e,f] T1, microwave, broadband (via fiber, cable, digital subscriber line), commercial wireless[g]	For backhaul: WiMAX, LTE For appliance to meter: IEEE 802.15.4,[h] ZigBee[g]	10–100 kilobytes/ second (kbps)/ node, 500 kbps for backhaul	2–15 seconds	5–15 minutes/ node	99–99.99%	High	Not necessary
Demand Response (Part of AMI)	Same as AMI	Same as AMI	14 kbps–100 kbps/ node or device	500 milliseconds (ms)– several minutes	35 days/ year	99–99.99%	High	Not necessary
Electric Transportation	Power line communications[i] wireless[h]	ZigBee, IEEE 802.15.4[h]	9.6–56 kbps, 100 kbps is a good target	2 seconds– 5 minutes	Daily	99–99.99%	Relatively high	Not necessary
Distribution Grid Management	Fiber, wireless,[j] satellite, cellular[g]	DNP3 (IEEE 1815), IEC 61850/ GOOSE,[k] WiMAX, LTE,[j] IP,[g] IEEE 802.15.4[h]	9.6–100 kbps	100 ms– 2 seconds	Continuous	99–99.999%	High	24–72 hours
Distributed Energy Resources and Storage	Fiber, wireless,[j] microwave, satellite[g]	DNP3, IEC 61850/ GOOSE[k] WiMAX, LTE,[j] ZigBee,[g] IEEE 802.15.4[h]	9.6–56 kbps	20 ms– 15 seconds	Continuous	99–99.99%	High	1 hour
Wide-area Situational Awareness (synchro-phasors[#])	SONET, ATM, Frame Relay, MPLS,[f,g] fiber, microwave, broadband over power line[g]	C37.118, IEC 61850/ GOOSE,[k] IP[h,l]	600–1,500 kbps	20 ms–200 ms	Continuous	99.999– 99.9999%	High	24-hour supply
Interutility communications (Southern California Edison)	Fiber, microwave, wired	ICCP[k]	> 45 megabytes/ second (mbps)	<50 ms (DS-3)	Continuous	99.999– 99.9999%	High	24-hour supply
Interregional data communications (ISO New England)	Standard telco T1 circuits with copper endpoints (NERCNet)	IP	256 kbps	20–200 ms	Continuous	99.999%	High	24-hour supply
Market data communications (ISO New England)	Wired	IP	18 mbps + 45 mbps connections	20–200 ms	Continuous	99.999%	Relatively high	24-hour supply

Notes:

* Communications between the utility and smart meters have different requirements than those between smart meters and appliances, although these are sometimes lumped under the category "advanced metering infrastructure." While the former necessitate reliable communications over long distances, the latter necessitates low latency over short distances.

A significant synchrophasor initiative is the North American SynchroPhasor Initiative. A communications network called NASPINet to support these technologies is under construction. More information may be found at http://www.naspi.org.

[a] Indicated column in source table from: U.S. Department of Energy, *Communications Requirements of Smart Grid Technologies, Appendix A* (Washington, DC, 2010), http://www.doe.gov/sites/prod/files/gcprod/documents/Smart_Grid_Communications_Requirements_Report_10-05-2010.pdf.

[b] "Frequency" developed from: U.S. Department of Energy, *Communications Requirements of Smart Grid Technologies, Appendix A* (Washington, DC, 2010), http://www.doe.gov/sites/prod/files/gcprod/documents/Smart_Grid_Communications_Requirements_Report_10-05-2010.pdf.

[c] N. Pavlidou, A. J. Han Vinck, J. Yazdani, B. Honary, "Power line communications: State of the Art and Future Trends," *IEEE Communications Magazine* 41, 4 (April 2003): 34–40.

[d] EDN Europe, "Maxim and Sagem to Develop Power-Line Comms for EDF," press release, December, 12, 2008, http://www.edn-europe.com/maximsagemtodeveloppowerlinecommsforedf+article+2679+Europe.html.

[e] V. C. Gungor and F. C. Lambert, "A Survey on Communication Networks for Electric System Automation," *Computer Networks* 50, 7 (2006): 877–97.

[f] M. McGranaghan, D. Von Dollen, P. Myrda, and E. Gunther, "Utility Experience with Developing a Smart Grid Roadmap," presentation at IEEE Power and Energy Society General Meeting, Pittsburgh, PA, July 20–24, 2008.

[g] U.S. Department of Energy, *Communications Requirements of Smart Grid Technologies: Department of Energy* (Washington, DC, 2010), http://energy.gov/sites/prod/files/gcprod/documents/Smart_Grid_Communications_Requirements_Report_10-05-2010.pdf.

[h] Personal communication with Exelon Staff, April 25, 2011.

[i] Renault Nissan, "Renault and EDF Strengthen Collaboration on Zero-Emission Electric Vehicle," press release, June 22, 2009, http://www.media.renault.com/download/media/specialfile/9210_1_5.aspx.

[j] V. K. Sood, D. Fischer, J. M. Eklund, and T. Brown, "Developing a Communication Infrastructure for the Smart Grid," presentation at IEEE Electrical Power & Energy Conference, Montreal, QC, Canada, October 22–23, 2009.

[k] Personal communication with Southern California Edison Staff, March 15, 2011.

[l] QualityLogic, "IEEE C37.118 PMU Communications," http://www.qualitylogic.com/Contents/Smart-Grid/Technology/IEEE-C37_118.aspx.

Standards and Interoperability

As more components are introduced into the communications infrastructure, ensuring interoperability among communications devices via standardized communications protocols and other interface standards will be critical.[7] The U.S. National Institute of Standards and Technology (NIST) Cybersecurity Working Group identified 137 interfaces between different grid systems.[8] For example, every smart meter and most sensors and major pieces of equipment at generating plants and substations will have communications modules—using millions of components from potentially hundreds of manufacturers. Software applications will similarly be provided by different developers. After installation, the technologies of the communications infrastructure will continue to evolve, requiring ongoing interoperability assessments and review. "Backward compatibility" will be required since newer equipment will have to operate alongside older equipment, even though this may decrease the functionality available.

From a cybersecurity perspective, interfacing so many different hardware and software components introduces vulnerabilities—especially when new and legacy hardware and software need to operate together. For example, implementing customer demand response involves power flow management at the distribution level, interfacing AMI, distribution grid management systems, and billing systems across large numbers of customers, not all of whom will have installed equipment from the same manufacturer, or even the same generation of equipment. The presence of so many interfaced components increases system complexity as well as the number of potential cyber vulnerabilities.

Standardization around a set of communications protocols is critical to achieving interoperability. Communications protocols are the rules and formats for communicating digital data. The protocol in conjunction with the communications media in large measure determines the data rate, latency, security, and reliability of the communications network. The 2007 National Energy Technology Laboratory report prescribes "an open communications architecture that supports 'plug and play' interoperability" and "universally accepted standards for these communications…defined and agreed upon in the industry."[9] NIST has tackled this problem by organizing a public–private partnership, the Smart Grid Interoperability Panel (SGIP), to identify standards for the grid as well as address gaps where standards are lacking; the first version of the resulting NIST report was published in 2010.[10] The second version became available for public comment October 25, 2011. Trading off the deployment of new technologies against interoperability requirements will become a major challenge for utility engineers.

Standardization around a set of communications protocols is critical to achieving interoperability.

Several debates over protocol choice are ongoing. For example, the successful deployments of new devices in locations that wired communications cannot reach economically can only be achieved with secure, wide-area, broadband wireless communications; two important wireless communications protocols are Worldwide Interoperabillity for Microwave Access (WiMAX) and Long Term Evolution (LTE), although momentum is clearly on the side of LTE. The home-area network industry is also debating different protocols for communicating among appliances and smart meters, including ZigBee, Inseon, Z-Wave, and X10. While the ZigBee protocol appears to have the most momentum in this area, other protocols cannot yet be ruled out.

Internet Protocol (IP) is the core protocol of the public Internet, defining the message formats for transmitting data across networks. Because IP is already used almost universally, commercially available software and hardware systems are designed to process IP traffic and protect IP-based networks from intrusion, thus making IP the obvious choice for most networking applications.[i] In July 2011, NIST's Smart Grid Interoperability Panel plenary session formally approved a set of IP protocols, outlined in the document "Internet Protocols for the Smart Grid," for use in the grid.[11] Indeed, IP is already in use in the grid, and IP-based networks are predicted to be important for a number of smart-grid and other future applications.[12] DOE also has received recommendations from several utility and telecommunications industry representatives that grid communications be standardized on IP. While some application-specific protocols may have better characteristics in limited cases, IP may quickly become an important protocol of choice for general deployment.[ii]

Decisions to standardize on specific protocols require input from a wide range of industry stakeholders, and federal agencies play an important convening role.

Decisions to standardize on specific protocols require input from a wide range of industry stakeholders, and federal agencies play an important convening role. For example, the NIST identified five standards for the Federal Energy Regulatory Commission's (FERC) consideration in October 2010.[13] The Energy Independence and Security Act of 2007 gives FERC responsibility for "adopting" standards recommended by NIST, but it is unclear how that responsibility will be used.[14] At this stage, FERC has determined that there is not sufficient consensus regarding these standards and declined to adopt them. Other groups support this decision. The National Science and Technology Council suggests that "embracing standards as best practices in the field" rather than requiring mandatory adoption will be sufficient to ensure the development of the future grid.[15] The Electric Power Research Institute (EPRI) adds that "consensus-based standards deliver better results over [time]."[16] Additionally, the U.S. Government Accountability Office (GAO) finds that FERC lacks an approach to monitor industry compliance with any related standards it adopts in this process.[17]

The key trade-off is between early standardization (which may limit innovation) and late standardization (which may delay adoption and lead to future interoperability problems). In the short run, NIST's facilitation of recommended standards will encourage market entry and facilitate interoperability. The fundamental question is how to ensure that innovation continues in and around the standardization process. The imposition of detailed federal standards beyond what comes out of this process would not appear to be productive, although federal agencies, state public utility commissions (PUCs), utilities, and consumer groups each have important roles to play as participants in the standard-setting process.

[i] It is important to note that the use of IP for grid data communications is not the same as using the public Internet. In most cases, the discussion of IP networks for grid communications envisions fully separate networks that are not connected to the public Internet, although some data communications applications do envision using the public Internet. These are separate debates. For the electric grid, it will be vital to keep critical grid communications systems from "talking" to the public Internet and becoming infected as a result.

[ii] Even this should be viewed as an evolving situation, although changes may be a decade or more away. For example, the National Science Foundation supports a Global Environment for Network Innovations program, which aims to design protocols that can run on the Internet in parallel with IP to reduce latency and improve security for future applications (see http://www.geni.net/).

FINDING

The ability of utilities to incorporate technological developments in electric grid systems and components on an ongoing basis will be critical to mitigating the data communications and cybersecurity challenges associated with grid modernization. Development and selection processes for interoperability standards must strike a balance between allowing more rapid adoption of new technologies (early standardization) and enabling continuous innovation (late standardization).

Ownership of Data Communications Networks

The ownership of grid data communications networks is also the subject of significant debate. At issue is whether to base future grid communications on utility-owned private networks or facilities operated by or leased from telecommunications companies. Traditionally, utilities have built private networks to support applications with critical latency, reliability, and security requirements and used commercial ones for applications with less stringent requirements.

Ultimately, the choice depends on the assessment each company makes about cost (capital versus operating, often treated differently in utility regulation), reliability, availability, and control. Utilities cite all factors as justifying direct ownership; for example, integrated utilities claim that during emergencies, commercial networks will be flooded with traffic and possibly become unusable by utilities that would have to compete for access to the networks.[18] Using public communications networks in the electric grid also establishes more interdependencies between the telecommunications and electric power industries, which could pose security and reliability problems, for example, by increasing the vulnerability of both industries to cascading failures that spill over from one industry to another.[19]

Telecommunications companies, on the other hand, maintain that commercial networks can satisfy the requirements of the grid.[20] The Federal Communications Commission (FCC) has stated that because "97.8% of Americans are already covered by at least one 3G network, a hardened commercial wireless data network could serve as a core part of the Smart Grid."[21] The FCC wants to begin testing the reliability and resilience of these networks and has recommended that states reduce disincentives to using them for grid communications. However, it does not ultimately endorse one specific ownership model over another, recognizing that specific circumstances must be taken into account.[iii] Further, no study provides definitive data to fully support either approach, which leads to the conclusion that opportunities exist for both utility-owned and commercial networks in a regulatory environment that encourages both equally.

At issue is whether to base future grid communications on utility-owned private networks or facilities operated by or leased from telecommunications companies.

[iii] In its National Broadband Plan, the FCC makes the following recommendations on the issue of grid data communications network ownership: "The country should pursue three parallel paths. First, existing commercial mobile networks should be hardened to support mission-critical Smart Grid applications. Second, utilities should be able to share the public safety mobile broadband network for mission-critical communications. Third, utilities should be empowered to construct and operate their own mission-critical broadband networks. Each approach has significant benefits and trade-offs, and what works in one geographic area or regulatory regime may not work as well in another. Rather than force a single solution, these recommendations will accelerate all three approaches."[22]

A related regulatory issue is the allocation of spectrum for utility communications. Utilities currently use licensed and unlicensed spectrum

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that is shared with other users and uses. The choice of spectrum often depends on the specific application and features of the service territory—for instance, in rural areas interference is less of an issue than in urban areas.[23] While these considerations have historically dominated utilities' thinking about spectrum, the utilities are increasingly focused on how they will get access to spectrum during emergencies. One of the questions being debated is whether utilities should share networks with public safety users—police, firefighters, and ambulance technicians—or have separate spectrum. In its National Broadband Plan, the FCC recommends that Congress consider amending the Communications Act of 1934 to allow utilities to use the public safety network in the 700 megahertz band and that the National Telecommunications and Information Administration and FCC continue to identify new uses for federal spectrum, especially with respect to the smart grid.[24]

In contrast, American Electric Power, Utilities Telecom Council, and other major electricity companies and utility trade groups support dedicated wireless spectrum for utilities' exclusive use, arguing that it will facilitate grid development.[25] Resolution of this question by the FCC requires considering the role of electricity service in servicing all other public safety users, particularly in times of natural or other disaster, and how that is best accomplished.

9.2 CYBERSECURITY OF THE ELECTRIC GRID

Cybersecurity refers to all the approaches taken to protect data, systems, and networks from deliberate attack as well as accidental compromise, ranging from preparedness to recovery. Increased data communications throughout the electric grid will introduce new cybersecurity risks and challenges, to both local and wide-scale grid systems. Some examples follow:

- **Loss of grid control** resulting in complete disruption of electricity supply over a wide area can occur as a result of errors or tampering with data communication among control equipment and central offices.
- **Consumer-level problems** ranging from incorrect billing to interruption in electric service can be introduced via smart meter tampering.
- **Commuting disruptions** for electric vehicle operators can occur if recharging stations have been modified to incorrectly charge batteries.
- **Data confidentiality breaches**, both personal and corporate, can provide information for identity theft, corporate espionage, physical security threats (for example, through knowing which homes are vacant), and terrorist activities (for example, through knowing which power lines are most important in electric distribution).

As observers from industry, government, and academia have recognized, the need to mitigate such risks makes grid cybersecurity an important concern for society at large as well as for individual companies. For example, the 2009 NERC Long-term Reliability Assessment includes cybersecurity as one of six issues projected to be of high likelihood and consequence within 10 years.[26] For the grid, an increase in the number of vulnerabilities—

along with the increasing interest among people and organizations with bad intent—increases the likelihood that risks will become actual events due to both accident and malfeasance. Indeed, in an article for the National Academy of Engineering, Massoud Amin, Professor at the University of Minnesota and formerly of EPRI, states that "cyber systems are the 'weakest link' in the electricity system."[27] It will take a determined cybersecurity-aware review of the design and implementation of grid components and operational processes to reduce the likelihood of attack and the scope of potential impact.

The challenges to maintaining cybersecurity of the electric grid come from several characteristics of the future grid:

- **New control systems and processes:** Control over large amounts of information generated from grid operations at the individual utility and even consumer level will require new control and management systems and processes.

- **Components:** The electric grid will be composed of components from multiple suppliers, with multiple interfaces and protocols, and relying on multiple standards.

- **Continuous transition:** The information and communications technologies (ICT) used in the grid will continue to change at a faster rate than utilities can change components in the grid, resulting in incompatibilities and security vulnerabilities between existing and new ICT.

These characteristics of the future grid make it especially difficult to develop plans for improved cybersecurity, although efforts have been made and many more are under way to assist industry with this task. The Homeland Security Act of 2002 gave the U.S. Department of Homeland Security (DHS) primary responsibility for developing a comprehensive national plan to secure critical infrastructure. In December 2003, Homeland Security Presidential Directive 7 designated 17 critical infrastructure sectors and named the DOE to lead protection and resilience-building activities in the energy sector, including electricity. DHS and DOE produced a plan for that sector, as part of the National Infrastructure Protection Plan, published in June 2006, and it has been updated since.[28]

It will take a determined cybersecurity-aware review of the design and implementation of grid components and operational processes to reduce the likelihood of attack and the scope of potential impact.

In 2006, a Roadmap to Secure Control Systems in the Energy Sector was prepared for the DOE and DHS, which have been collaborating on its implementation since 2007.[iv, 29] In 2010, the National Broadband Plan recommended (and the FCC is following up on) creating a more far-reaching Cybersecurity Roadmap for communications.[30] That same year, the GAO issued a report on challenges to cybersecurity research and development.[31] In 2011, the DOE announced a public–private collaboration including NIST and NERC to develop guidelines for cybersecurity risk management in the electric sector.[32]

[iv] The Energy Sector Control Systems Working Group, a public–private partnership that includes representatives from the DOE and DHS, is tasked with implementing the roadmap. See http://www.controlsystemsroadmap.net/workinggroup.shtml. The 2011 update to the 2006 roadmap is now available at http://www.controlsystemsroadmap.net/pdfs/roadmap.pdf.

In response to heightened Congressional concern with cybersecurity, the administration issued a legislative proposal in May 2011 that would make DHS responsible for working with industry to enhance the cybersecurity of all the nation's critical infrastructure.[33] Two months later, the Senate Energy Committee reported out S. 1342, a bill that would make DOE and FERC responsible for cybersecurity of the electric power system. (Similar legislation, H.R. 5026, had passed the House in June 2010.) While both proposals would designate a single responsible agency, the administration seems to have given more weight to DHS's broad expertise in cybersecurity and its multisector responsibility, while the Congress seems to have given more weight to DOE and FERC's specific knowledge of the electric power industry.

With rapidly expanding connectivity and rapidly evolving threats, making the grid invulnerable to cyber events is impossible, and improving resilience to attacks and reducing the impact of attacks are important.

With rapidly expanding connectivity and rapidly evolving threats, making the grid invulnerable to cyber events is impossible, and improving resilience to attacks and reducing the impact of attacks are important. As a joint NERC–DOE report notes, "It is impossible to fully protect the system from every threat or threat actor. Sound management of these and all risks to the sector must take a holistic approach, with specific focus on determining the appropriate balance of resilience, restoration, and protection."[34] For the electric grid in particular, cybersecurity must encompass not only the protection of information but also the security of grid equipment that depends on or is controlled by that information. And its goals must include ensuring the continuous and reliable operation of the electric grid.

The scale of investment required to improve cybersecurity is not insignificant. A 2011 EPRI report estimated that a $3.7 billion investment is needed for grid cybersecurity, although this amount is relatively low compared to its estimate of a net total investment over 20 years of between $338 and $476 billion needed to realize the benefits of the smart grid.[35] But as GAO points out in a 2007 report, it is difficult to make the business case for investing in critical infrastructure cybersecurity because the probability of a serious event is still very low and the consequences are so difficult to quantify.[36] In a more recent report of 2011, the GAO finds a remedy in cybersecurity metrics for helping utilities show a return on a particular cybersecurity investment. "Until such metrics are developed," the GAO concludes, "there is increased risk that utilities will not invest in security in a cost-effective manner, or have the information needed to make informed decisions on their cybersecurity investment."[37] The National Science and Technology Council, reporting to the White House, also recognizes the importance of cost-effectiveness: "The [current] Administration's approach to a secure grid is to pursue a thoughtful, cost-effective strategy that ensures the largest improvement in security and the greatest return on investment."[38] Unfortunately, finding the approach that balances risk, impact, and cost will be a challenge for industry and government alike.

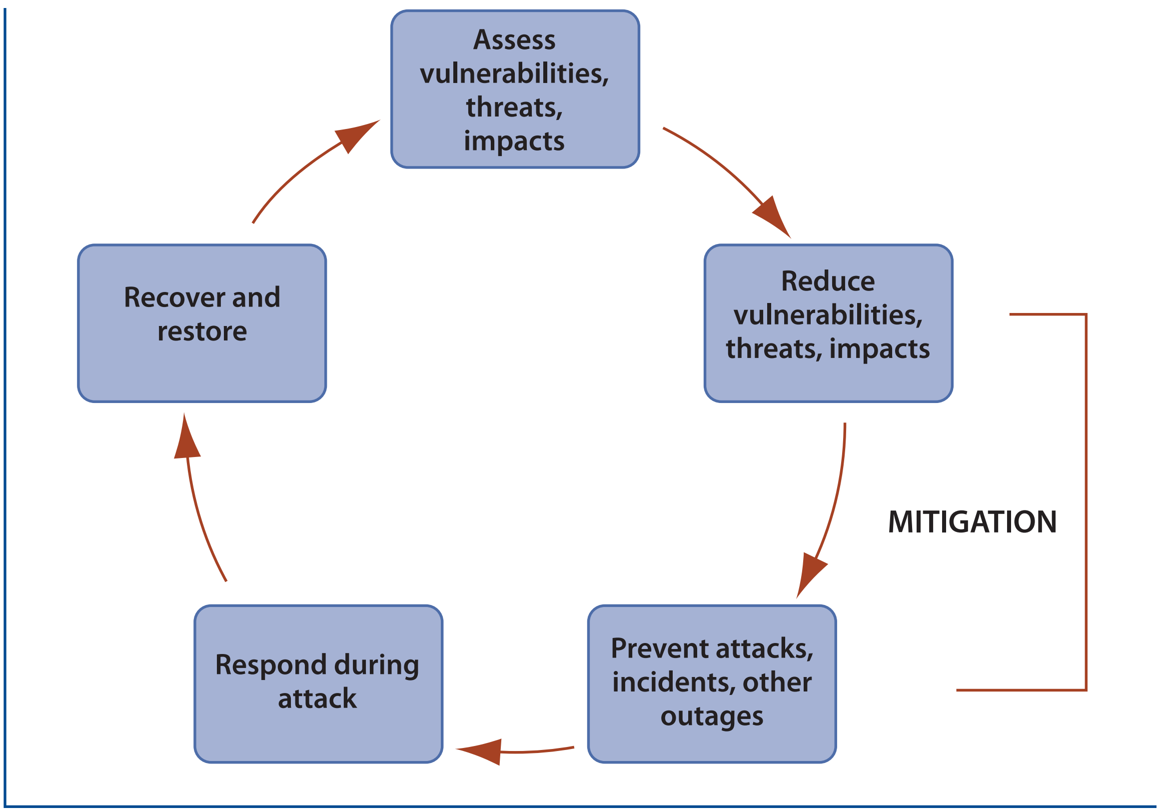
System Security and Designing for the Security Life Cycle

System security focuses on the holistic protection of systems and the prevention of attacks, beginning with system design and including the implementation of physical and electronic barriers, and activities to identify potential attackers. Figure 9.3 illustrates a multistep life-cycle approach to systems security that can be applied to analyzing cybersecurity of the electric grid.

The first step is to assess vulnerabilities, possible attack vectors, and the potential impact of attacks. NIST, overseeing a large public–private working group, published Guidelines for Smart Grid Cyber Security in 2010 to address these issues.[39] Risk mitigation, which focuses on reducing system vulnerabilities as well as preventing attack, should follow. Utilities, their suppliers, and government agencies all have a role to play: utilities are responsible for overall secure system design, operations, and control; suppliers ensure their equipment is designed for security; and government agencies carry out risk assessment, testing, certification, standards setting and regulation. Mitigation involves both reducing vulnerability and preventing attack, as the NERC–DOE High-impact, Low-frequency Event Risk report notes: "Perhaps the first step to adequate mitigation is the acknowledgment that fully protecting the system from a coordinated attack is not possible...As a result, effectively mitigating the effects of a coordinated attack on the system will require a strong mix of preventative measures designed to build on the inherent resilience of the system and preparatory measures that will enable system operators to recognize an attack and respond to it when it does occur."[40] Systems should all be designed to respond to attacks—for example, by ejecting attackers from the system or containing a problem to a localized area. In the case of the grid, one such tactic is to isolate circuits to minimize outages. Finally, systems should recover from the effects of an attack by restoring operations and retrieving or repairing corrupted data.

As the grid evolves, vulnerabilities and attack types will change quickly just as modern computer viruses do. Anticipating the possible impacts of attacks and focusing on resilient and robust responses can mitigate the negative effects more efficiently than attempting to

Figure 9.3 Security Life Cycle



defend against every new type of attack.[41] We believe the natural evolution of grid information technologies already points toward such an approach: the development and integration of increasingly rapid and accurate systems control and monitoring technologies should facilitate quicker attack detection—and consequently, shorter response and recovery times. Cyber-attack response and recovery measures would be a fruitful area for ongoing research and development in utilities, their vendors, and academia.

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As communications systems expand into every facet of grid control and operations, their complexity and continuous evolution will preclude perfect protection from cyberattacks. Response and recovery, as well as protection, are important concerns for cybersecurity processes and regulation. Research funding will be important to the development of best practices for response to and recovery from cyberattacks.

Much as cybersecurity was not a key factor in the design of the Internet, cybersecurity has not been a high priority—until recently—in designing grid components. This can result in highly disturbing or even disastrous situations: consider the emergency shutdown of a nuclear power plant in Georgia after a software update on one system reset an important database on another when the two systems were linked.[42] The Aurora experiment and the Stuxnet worm are two additional examples discussed later in this chapter. Experience from other domains shows that the most effective security is "designed in" and requires consideration of all aspects of the security life cycle.

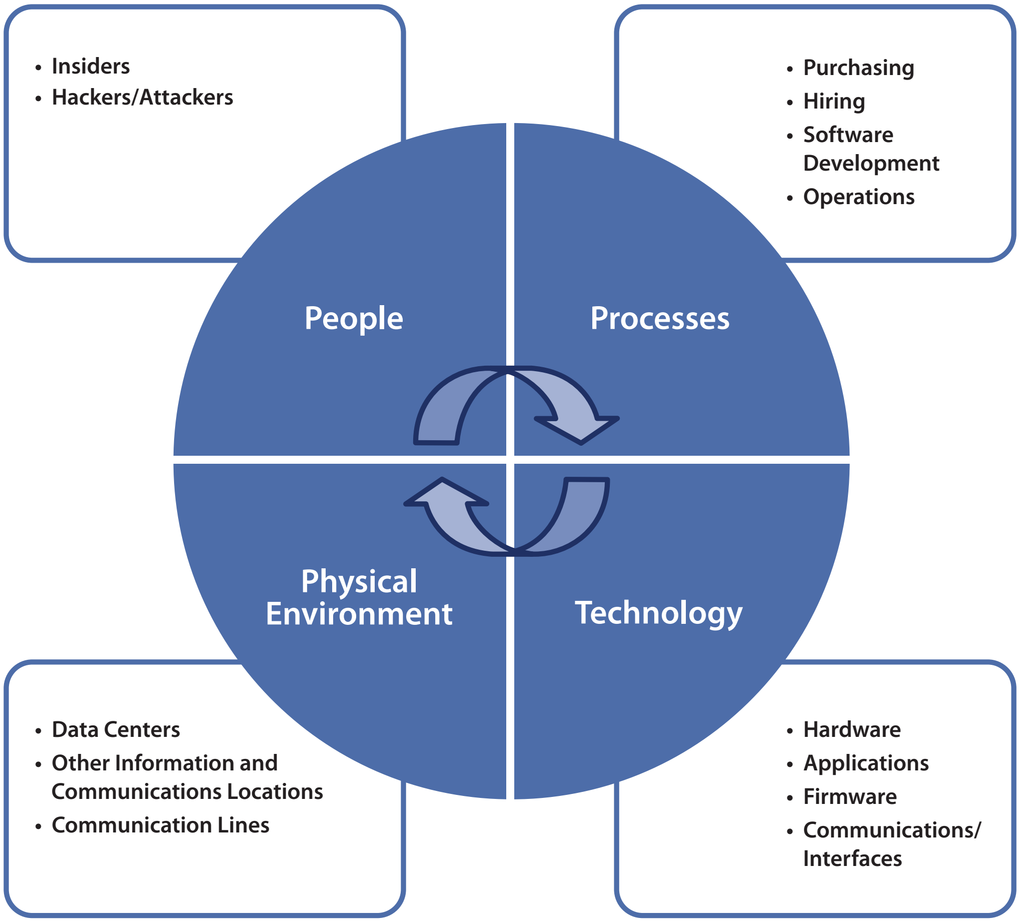
Vulnerabilities

Although effective attack responses will become important for the continued operation of the grid, the mitigation of grid cybersecurity vulnerabilities remains critical and is a responsibility of manufacturers, utilities, and the government. Achieving this task will increasingly require the electric sector to protect its IT and telecommunications infrastructure.[43] As the grid modernizes, the growing prevalence of information and communications technology in the system and the large numbers of personnel with access to it will create an ever-evolving cybersecurity situation, where the relative importance of specific vulnerabilities changes continuously as new types of attacks emerge. In particular, the introduction of the Internet to grid operations has introduced additional vulnerabilities to the power system, especially where corresponding security controls have not been put in place.[44]

Cybersecurity vulnerabilities can arise from weaknesses in personnel, processes, technology, and the physical environment. Figure 9.4 shows examples in these categories.

Security issues occur because of actions taken by outside hackers and attackers, and also by disgruntled employees. With their insider knowledge, these individuals may instigate significant damage; for example, in 2000, an insider attack on the Australian water system caused the spillage of 800,000 liters of sewage into rivers and parks in Queensland.[45] A 2005 study by Robert Turk at the U.S. Computer Emergency Readiness Team's Control Systems Security Center found that insiders perpetrated 38% of control system cybersecurity incidents.[46] More recently, DHS has issued a warning to utilities that "insiders and their actions pose a significant threat to the infrastructure and information systems of U.S. utilities."[47]

Figure 9.4 Categories of Cybersecurity Vulnerabilities



Process security ensures that all operational processes include measures to protect the enterprise, its equipment, and its products. In the case of grid cybersecurity, examples include running or validating the results of various security checks on equipment before certifying them for purchase, performing outside security checks on potential IT and communications hires, implementing software development processes that include security checklists, and doing physical security checks of computer and communications equipment areas.

Technology security involves the design, implementation, and interoperability of communications and IT hardware, application software, device-embedded software ("firmware" typically provided by the manufacturer), communication protocols, and communications interfaces. The future grid also will have millions of programmable devices—most notably smart meters, but also electric vehicles, PMUs, devices in electric grid substations, and other equipment—that all present software application and firmware security vulnerabilities.

Communications security includes mitigating protocol vulnerabilities that can impact the ability of communications network protocols to transmit their data securely. In this case, some security issues and solutions may be dependent on the protocol in use. Communications interfaces within and between grid systems introduce critical vulnerability points into the electric grid network. For example, customer demand response might involve an interface between AMI, distribution management systems, and billing systems spanning a large number of customers, with potentially multiple types and versions of communications components, even within a single utility's environment. Not only will such a system incur additional interoperability costs, but the additional complexity increases vulnerability to data tampering and other security issues. In its 2010 guidelines, NIST discusses such cybersecurity "use cases" and vulnerability classes in detail.[48]

Control over physical access to grid hardware and facilities is also necessary to eliminate tampering at software and communications interfaces. Gaining physical access to a communications router or controller would allow a knowledgeable person to significantly disrupt data flow. Likewise, gaining access to a corporate data center or other equipment location would allow direct control over equipment.

Ultimately, utilities will have to consider what cybersecurity protections should be used in each new technology and system they implement. Examining real-world cases of how components and technologies are used in the grid will be just as important as considering individual components and their place in the total system environment. To demonstrate the multifaceted security risks that individual grid technologies face, Table 9.3 charts some attack vectors, possible impacts, and potential solutions related to one technology, AMI.[v]

Component and Systems Testing

Rigorous testing of individual system components, complemented by integrated systems testing, can help mitigate cybersecurity risks and develop better system responses when vulnerabilities are breached. Several utilities and industry stakeholders, including the Edison Electric Institute (EEI) and NERC, support federally sponsored system testing because of the government's technical expertise in the area of cybersecurity.[49]

One notable government effort under way is the National SCADA (supervisory control and data acquisition) Test Bed program set up by DOE and operated by the Idaho National Laboratory, Sandia National Laboratory, and other partners. In this voluntary program, the lab conducts vulnerability assessments for control systems and third-party vendor equipment. Testing there has effectively revealed previously unknown vulnerabilities in control systems. For example, the "Aurora" experiment in 2007 discovered a severe weakness that would have enabled hacking into electric power control systems with potentially disastrous results.[50] After NERC's initial advisory shortly after this discovery, three years passed before it recommended mitigating strategies to the industry, with requirements for progress reports from covered utilities every six months.[51]

More rigorous procedures with regard to security testing might have reduced damage caused by the highly publicized Stuxnet worm, which was discovered in 2010 to have entered control systems using a common default password in certain SCADA equipment from Siemens.[52] As early as September 2006, the Idaho National Laboratory had warned of the threat posed by weak passwords.[53] But because the National SCADA Test Bed procedures are voluntary and partner organizations sign nondisclosure agreements about work done there, it is unclear whether the Siemens system had undergone such testing or, if it had, whether the recommendations had been put into practice.

[v] Case studies on the cybersecurity risks associated with not just AMI but also distribution grid management and electric vehicles are available from the Advanced Security Acceleration Project for the Smart Grid, a collaborative funded by DOE and various utility companies to accelerate the development of security requirements for the grid. See http://www.smartgridipedia.org/index.php/ASAP-SG.

Table 9.3 Attacks on Advanced Metering Infrastructure, with Possible Impacts and Solutions

Attack Vector	Impact	Possible Solutions	Solution Requirements
Physical Attack on Meter	Energy theft Incorrect energy usage data sent Theft of energy-usage data Theft of personal/billing information Disruption of electricity supply	Tamper-proof sealing or physical locks[a] Tamper-detection mechanisms[b] Automated system protection[c] (e.g., data erasure) Regular updates of meter firmware, security certificates[d] Asymmetric encryption[d] Frequent but irregular change of cryptographic keys, pre-installation of keys[e] Design architecture to store data for minimum time necessary[b]	Sufficient network bandwidth for updates[d] Formal industry agreement on a "sufficient" bandwidth Minimum security standards (regularly updated) regarding software security, tamper-proof and tamper-detection mechanisms Policy requirement for regular software updates to meet security standards Policy requirement for automated system protection
Denial-of-Service Attack on Meter Data Collection Point	Denial of service to connected local area meters, disruption of local-area network Possible upstream cascading effects on utility data network due to missing data	Tamper-detection mechanisms at collection points Automated system protection[c] (e.g., data erasure)	Standards for tamper-detection mechanisms
Software Attack on Utility Meter Data Management System	Widespread theft of energy-usage data Widespread theft of personal/billing information Disruption of electricity supply Disconnection of meters	Utility security policies to prevent unauthorized access Detection methods for unauthorized access/tampering Separation of electricity delivery system from energy data management system	Corporate security policies User access policies Back-end system design policies Implementation of utility-side tamper-detection mechanisms

Sources:

[a]S. McLaughlin, D. Podkuiko, and P. McDaniel, "Energy Theft in the Advanced Metering Infrastructure," in *Proceedings of the 4th International Workshop on Critical Information Infrastructure Security* (New York, NY: IEEE Press, 2009).

[b]R. Shein, "Security Measures for Advanced Metering Infrastructure Components," in *2010 Asia-Pacific Power and Energy Engineering Conference* (New York, NY: APPEEC and IEEE, 2010).

[c]InGuardians, *Advanced Metering Infrastructure Attack Methodology, Vol 1.0.* (Washington, DC, 2009).

[d]F. M. Cleveland, "Cyber Security Issues for Advanced Metering Infrastructure (AMI)," presented at the IEEE Power and Energy Society General Meeting, Pittsburgh, PA, July 20–24, 2008.

[e]C. Bennett and D. Highfill, "Networking AMI Smart Meters," presented at Energy 2030: IEEE Conference on Sustainable Energy Infrastructure, Atlanta, GA, November 17–18, 2008.

Assessments of system-level security also can help ensure appropriate security levels are maintained. In 2008, GAO undertook an extensive audit of control-system security in the largest U.S. public power company—the Tennessee Valley Authority. While it had begun several processes to improve cybersecurity prior to the GAO audit, management subsequently centralized cybersecurity responsibility so that cybersecurity and risk management policies would be more consistently applied to its control systems, and engaged a third-party to test for cybersecurity vulnerabilities.[54]

Owing to rapid changes in cybersecurity risk as grid technologies develop, a system's level of security can change over time. Furthermore, the complex and quickly evolving technologies, systems, and security policies of the modernizing grid make it difficult to issue generic security design guidelines that remain appropriate over time. These factors reinforce the importance of ongoing component and systems testing.

Continuous Technology Transition

Some policy makers and state utility commissions are already concerned by the fast evolution of smart grid technologies and communications solutions. Indeed, a recent proposal by Baltimore Gas & Electric to deploy 1.36 million smart meters in Maryland was initially rejected by the Maryland PUC because of the high risk that meter technology will become obsolete, among other reasons. This will be the case if meters are installed without communications flexibility and/or the protocol they use is abandoned later on in the grid development process.[55] Looking even further ahead, EEI remarks, "Smart Grid technology itself may have a substantially shorter life-cycle than the equipment it replaced."[56]

Continuous transition also raises important cybersecurity issues. A specific security challenge is the problem posed by the smart meters that have already been installed. An estimated 20 million AMI meters have been deployed nationwide as of June 2011.[57] The security features of these meters may be deemed inadequate under future cybersecurity standards, and the earliest smart meters may have been developed without taking into account the NIST Guidelines for Smart Grid Cyber Security released in 2010 or the AMI Security Profile developed by the Advanced Security Acceleration Project for the Smart Grid (see note v).[58]

Utilities have stated that it is often necessary to continue using legacy equipment at least while new equipment is being installed and that it can be difficult to justify installing new equipment solely for security reasons.[59] One method of addressing the issues posed by systematic upgrade processes has been to insert a "shield," or encapsulating device, between new and old grid components. The shield protects the devices below it from modern cyberattacks while the lower-level devices are being upgraded more slowly. The power technology firm ABB explains that such methods "encapsulate the given system within a secure zone of cyber protection so that it is isolated from direct contact with other systems, both within the utility firewall and outside it. Communication channels can also be secured by upgrading to modern protocols that support encryption, authentication and authorization mechanisms. Access to the legacy system can also be controlled by bolting on a new user interface layer along with the application of appropriate procedures for authorization."[60]

While continuous transition may pose cybersecurity risks to the grid, it may also present solutions. An industry observer has remarked that regulations encouraging continuous innovation in cybersecurity approaches can help ensure they remain able to meet the evolving threats to the grid.[61] It is also worth noting that innovation in cybersecurity technologies and strategies could be limited by uncertainties over future regulation for cybersecurity requirements, which would in turn hinder the development of a robust and resilient grid infrastructure.

Regulating Cybersecurity

Cybersecurity activities span all aspects of grid development and operations, from generation to transmission to distribution, and all aspects of risk management, from preparedness to prevention to response and recovery. Regulation of these activities is in the hands of multiple regulatory and legislative bodies or, in some cases, of no such body (e.g., for cooperative or municipal utilities).

The principal regulations regarding grid cybersecurity are the NERC Critical Infrastructure Protection (CIP) standards, which apply to the U.S. bulk power system. They require responsible entities in this industry to submit documentation that identifies critical assets—as defined by specific criteria—and verify their cybersecurity preparedness.[62] Noncompliance results in fines of up to $1 million per day, although no fines approaching that amount have been levied to date.

One question about the current CIP standards is whether they focus industry too much on reporting and documentation rather than substantial cybersecurity improvements. CIP standards have been through multiple revisions with each aimed at helping to sharpening this focus toward improved cybersecurity. On a positive note, in 2010 an Arizona utility was able to detect and respond to a software virus attack with the help of systems originally installed to ensure CIP compliance.[63] On the other hand, a grid-system vendor reported that a utility met CIP requirements by decreasing the level of sophistication in its network—ironically making the system less able to detect and respond to attacks.[64] In addition, a 2011 audit by the DOE Inspector General criticized FERC for approving CIP standards that did not contain commonly used security practices and adopted a poor approach to implementation.[65] Further modifications of the CIP standards are in progress.

The NIST Guidelines for Smart Grid Cyber Security go into greater depth on technical requirements, identifying different communications interfaces that exist or are expected to exist in the grid and technologies to secure them.[66] Unlike the CIP standards, which are more process-oriented and focus on the bulk power system, NIST's work is technical in nature and covers both the transmission and distribution domains.[vi] As noted here, NIST also is working to facilitate the adoption by industry of appropriate national and international standards for the grid. Given the differences in focus and scope between the CIP and these standards, it appears unlikely that they would overlap substantially. However, the very presence of the two processes may confound stakeholders subject to both.[vii]

One question about the current CIP standards is whether they focus industry too much on reporting and documentation rather than substantial cybersecurity improvements.

Apart from NERC's CIP standards, recommendations from NIST, and some nascent state PUC rulings (which do not cover municipal and cooperative electric distribution companies), there are no laws, regulations, or formal minimum standards for grid cybersecurity.

[vi] A 2011 GAO report criticizes the NIST guidelines for their lack of information on combined cyber–physical attacks and the absence of a final schedule for updating the guidelines.[67]

[vii] The FCC identified the potential for conflicts between the existing CIP requirements and other standards as an area of concern and opined that the resulting ambiguity was slowing utility decision-making and deployment of some new technologies.[68]

Furthermore, NERC's jurisdiction is limited to the bulk power system.[69] The distribution systems of investor-owned utilities, which account for approximately 66% of electricity sales, are regulated by individual state PUCs, while municipal and cooperative distribution utilities do not fall under any regulatory authority.[70] That said, given the level of technical specialization necessary to develop effective cybersecurity defenses and the need to continually update them, it would be inefficient for policy makers to dictate detailed technical cybersecurity specifications. Organizations such as the Institute of Electrical and Electronics Engineers and the International Electrochemical Commission already have extensive standards-setting processes which NIST has drawn on in its role as facilitator of grid standards. Instead, policy makers could focus their efforts on establishing security best-practice frameworks, as the NIST guidelines propose, to ensure that security regulations allow for rapid improvement and do not stifle innovation.

Compliance with standards does not necessarily make the grid secure.

Finally, it should be carefully noted that compliance with standards does not necessarily make the grid secure. EPRI explains, "Cybersecurity technologies and compliance with standards alone are not enough to achieve secure operations without policies, ongoing risk assessment, and training."[71] Federal and state regulators are developing best-practice frameworks and model processes for response to and recovery from cyberattacks, based on a risk management approach, to help improve secure operations across the electric sector. For example, DOE, NIST, NERC and industry representatives are collaborating to develop an Electricity Sector Cybersecurity Risk Management Process Guideline, in draft form as of September 2011.[72] These important activities are all part of a "culture of security" that the utility industry must adopt.

While the consequences of a successful attack on the bulk power system are potentially much greater than an attack at the distribution level, the boundary between transmission and distribution has become increasingly blurry, and distribution-level cybersecurity risks deserve serious attention. Detailed consideration of the rapidly expanding interconnections between different levels of the grid will be critical to future efforts to address grid cybersecurity issues. State public utility commissions (which are generally responsible only for investor-owned distribution systems), municipal electric systems, cooperatives, and other public systems generally lack the expertise necessary to deal with cybersecurity issues.

FINDING

There is currently no national authority for overall grid cybersecurity preparedness. FERC and NERC have authority over cybersecurity standards development and compliance for the bulk power system, but there is no national regulatory oversight of cybersecurity standards compliance for the distribution system.

Forensics

Cyberattacks and accidents inevitably will occur in a system as large and complex as the grid. Forensics work focuses on discovering the root of cyber problems when they do occur and could significantly assist organizations in improving system design. Sharing this type of information with relevant stakeholders across the utility industry will allow the development of improved procedures and systems that can help prevent problems from reoccurring.

In the transportation industry, the National Transportation Safety Board analyzes major transportation events to identify sources of failure and makes recommendations for improvements to relevant government agencies, such as the Federal Aviation Administration. An analogous agency would be valuable in developing U.S. grid cybersecurity forensics. Because of the many parties involved in grid cybersecurity, such an agency might direct suggestions to industry and other stakeholders as well as to the federal government. DOE awarded two grants in September 2010 related to the creation of the National Electric Sector Cyber Security Organization, a nonprofit, independent entity that will serve such a function and facilitate information sharing between normally competitive or secretive parties more generally.[73] The organization will not have any regulatory authority. NERC also operates the Electricity Sector Information Sharing and Analysis Center. It exists to communicate threat indications, vulnerabilities, and protective strategies to industry members, government partners, and Information Sharing and Analysis Centers that have been established for other critical infrastructures. Experience in other industries shows that initiatives like these will be important to improving the reliability of the future grid.

9.3 INFORMATION PRIVACY AND SECURITY

Related to cybersecurity is the issue of information privacy and security. The future electric grid will collect, communicate, and store detailed operational data from tens of thousands of sensors as well as electricity-usage data from millions of consumers. This section discusses the issues that arise from making these data available to people who need them and protecting them from those who do not. Key questions that are being addressed by the industry and regulators include:

- What data are we concerned about?
- How do we determine who should access that data, when, and how?
- How do we ensure that data are appropriately controlled and protected?
- How do we balance privacy concerns with the business or societal benefit of making data available?

Since these types of questions have been widely discussed in regard to other industries and data, this report will not attempt to provide a general treatise on information privacy and security but will focus on issues specific to access, usage, and disclosure of data that will be produced by operation of the future electric grid.[viii] The electric utility industry and various government agencies are already concerned with these issues; recent major efforts by DOE, FCC, and NIST have solicited industry comments.[74] Indeed, the issue of protecting data privacy is not a new one for utilities. A resolution of the National Association of Regulatory Utility Commissioners more than 10 years ago urged the adoption of general privacy principles related to the use of utility customer information.[75]

Categories of Privacy and Security Concerns

Security and privacy issues are evident in both major types of grid data: operational data and electricity consumption data (or "consumer electric usage data," CEUD, according to the DOE terminology).

[viii] The study of information privacy deals with policy issues ranging from identification and collection to storage, access, and use of information. The study of information security deals with protecting information from unauthorized access and use as defined by information privacy rules or otherwise.

Grid operational data is data or information about electricity generation, transmission, and distribution components or systems not at the level of individual customers.[ix] Grid schematics, equipment and control signal specifications,

While privacy discussions in the popular press focus on consumer electric usage data, control over grid operational information is arguably more important.

and operating procedures are grid operational data. Load analysis of electricity flows across a transmission line and output logs from an electric generator at a hydroelectric plant are grid operational data. Improper disclosure of these or other operational information may result in tangible, or objective, competitive or societal harm.

CEUD is data obtained from measuring the electric usage of individual consumers, both commercial and residential.[x] Improper disclosure of consumer-level information, such as minute-by-minute electricity usage, may result in objective harm as well as subjective, or intangible, harm. Property theft and physical attack are examples of the former. There are also more subjective privacy concerns about the harm "in which the mere knowledge by a second or third party of one's private information is experienced [as] an injury."[76] Consumer anxiety over the installation of smart meters and wide-scale implementation of AMI arises from both types of concern, and both deserve important consideration.

Privacy and Security of Operational Data

While privacy discussions in the popular press focus on consumer electric usage data, control over grid operational information is arguably more important, certainly in terms of large-scale impact on grid operations. Improper disclosure of grid operational information—such as operational procedures, network topology, control signals, and load-analysis data—may result in objective security or competitive harms, up to and including use of this data to mount physical or cyberattacks on the grid, such as was demonstrated in the Stuxnet attacks and the Aurora experiment.

In the past, corporate interests dominated this discussion with the privacy concern that competitive information would be disclosed. However, in the current worldwide environment, the government is concerned with the protection of information from a security standpoint because enemies could use the information to determine grid vulnerabilities. The protection of grid operational information is being dealt with by NERC for the bulk power system[xi] and PUCs for the distribution system. The protection of grid operational information is commonly treated as a "security" issue rather than a "privacy" issue. Regardless of terminology, grid operational data protection deserves important consideration in policy and regulation.

[ix] While "information" and "data" are used somewhat interchangeably, they are related but different terms; information is processed data.

[x] Utilities also deal with "personally identifiable information" (PII) in the normal course of their operations, as do all companies in consumer-facing businesses. PII is any data or information that identifies an individual person or organization. For example, name, address, and phone number taken together are considered PII. The privacy issues related to PII have been addressed in many forums and are not discussed further in this report.

[xi] See, for example, NERC Regulation CIP-003-4, which specifies implementation of a "cyber security policy that represents management's commitment and ability to secure its Critical Cyber Assets."

As important as grid operational security is, improper CEUD disclosure often attracts more public attention because it has the potential to directly harm individuals. The remainder of this section will focus on the privacy issues related to CEUD.

Privacy and Security of Consumer Data

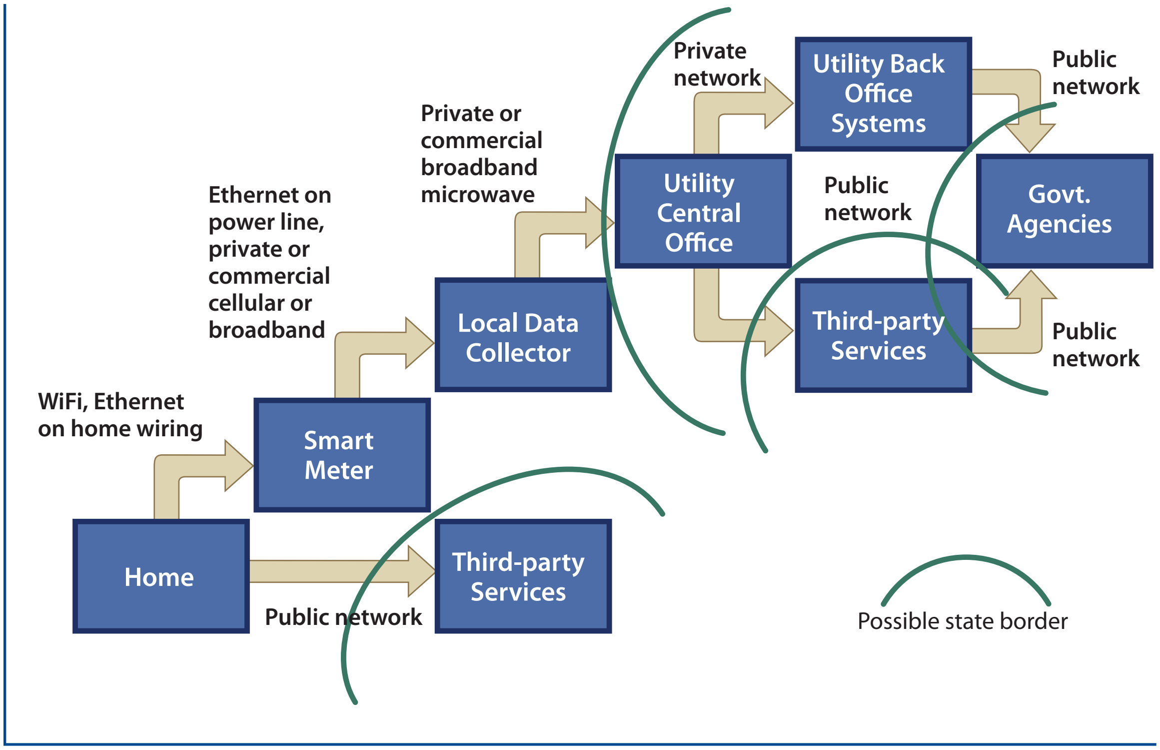
For decades, electricity meters were primarily a source of monthly measurements to be used in creating consumers' bills. Now, new smart meters can measure electricity usage multiple times each hour. As Figure 9.5 shows, these data flow across the electric grid communication network not only to utilities but potentially to suppliers of third-party services and government agencies (some of these flows may be of aggregated or summary data). Objective and subjective privacy concerns resulting from that data collection and use include identity theft; personal surveillance by law-enforcement agencies and others; energy-use surveillance by business competitors and third-party service suppliers; physical danger from criminals; and other misuse of data.[77] Note that these uses of CEUD have nothing to do with operation of the grid or providing ancillary services. For example, the *Columbus Dispatch* reported that an Ohio utility routinely responds to subpoenas for utility usage information in drug enforcement actions.[78] Information privacy concerns are not limited to one type of organization or one type of use. Corporations, governments, and criminals are all cited as potential users of CEUD for wide-ranging purposes that may or may not be considered proper or legitimate by individual or business consumers.

CEUD is collected on all consumers of electricity, and a disclosure by a major electric com0pany could affect millions of people and businesses. When electric usage was only measured once a month, most people were not particularly concerned about whether that data was protected or how it was used. But with millions of smart meters now installed, and tens of millions more on the way, access to the electric usage data they will generate is of much greater concern. These data do have many legitimate uses, including some that might be of value to home or business owners. For instance, the data can alert consumers to a malfunctioning appliance or equipment that is drawing excessive amounts of electricity. It can also facilitate demand response systems and general home and business energy management systems. However, because the potential exists for other, perhaps less desirable uses, there are opposing views within the industry and in government about collecting and protecting these data. The following list exemplifies some of the discussion points:

Information privacy concerns are not limited to one type of organization or one type of use.

- Data Collection
  - *Point:* Collecting detailed electricity-usage information will provide many benefits through the introduction of new services and efficiencies.
  - *Counterpoint:* Collecting detailed electricity-usage information (and making it available to consumers and third parties) opens a variety of data-disclosure issues and will incur significant costs to utilities, perhaps out of proportion to the benefits.

Figure 9.5 Consumer Electric Usage Data Flow



- Data Ownership

  – *Point:* Collected data is the property of the utilities, and these companies can determine what to do with it.

  – *Counterpoint:* CEUD is owned by the customer.

  – EEI expresses a third view: "The critical policy issue for Smart Grid development is not ownership of consumption data, but access to, usage and disclosure of that data."[79]

- Data Integrity

  – *Point:* Utilities have always protected consumer data. Existing laws provide adequate protections.

  – *Counterpoint*, as expressed by EEI: Utilities must update their policies and procedures to protect consumer data because smart grid technology "introduces new data collection and information sharing abilities related to customer energy usage, and raises significant privacy and data access issues."[80]

- Data Privacy

  – *Point:* Some consumers do not particularly care about keeping CEUD private.

  – *Counterpoint:* Other consumers do care. "A recent consumer survey conducted for EEI [indicates] that 46 percent of respondents believe it is 'very important' that their electricity usage be kept confidential, 29 percent believe it is 'somewhat important,' and 79 percent believe only customers and utilities should have access to smart meter information."[81]

We discuss these points further in the sections that follow.

Data Collection and Storage

Smart meters are capable of recording and transmitting electricity-usage information every few minutes. These and other measurement devices installed in homes and businesses will become even more capable in the future, potentially achieving almost continuous monitoring of the electric usage of HVAC units, lighting systems, or other electric appliances. The policy issues these technological advances raise include questions about what data should be collected, why and by whom, how collection and storage should be paid for, who controls such data, and how it should be protected.

Potential suppliers of new types of energy services advocate data collection and storage where they think it will enhance their future business. This often puts utilities in a position to collect data that perhaps will be of more value to other businesses and consumers than it will be to them, a situation that creates a potential regulatory concern when it comes to paying for the data collection and storage. Google, for example, has made the case to the California PUC that utilities should provide real-time electricity usage information to consumers, noting that the mere installation of a smart meter "does not automatically mean that consumers will receive" this information.[82] The Texas PUC engaged the utilities in forming a consortium that pays an outsourced vendor to provide a data repository and create a website for customer use.[83] In Ontario, the provincial government is creating a "meter-data management repository" to store CEUD and make it available for consumers.[84] In this effort, government is taking on a role where commercial interests may be too disjointed or at odds with one another.

It is also important to consider whether data should be collected when we have little immediate use for it. Collecting and storing large amounts of data costs money and poses the inherent privacy risk of inadvertent, or even malicious, disclosure. In the financial industry, the increasing number of disclosures has spawned new laws and regulations, such as the Fair Credit Reporting Act and the Payment Card Industry Data Security Standards.[xii] The surest way to limit these risks is to collect only the minimal amount of data needed for known purposes, an approach advocated by some with regard to the future electric grid, and embodied in the oft-cited privacy guidelines published by the Organisation for Economic Co-operation and Development.[xiii, 85] However, this approach ignores the role of data collection in advancing the evolution of the electric grid. Given the relative immaturity of new grid technologies, demand response strategies, variable pricing policies, and the expected development of even more new capabilities that will enhance the efficiency of the grid, it would appear too limiting to mandate that all data collection has to have a currently acknowledged purpose. The California PUC, for example, is requiring that utilities disclose the purpose for collecting each type of data as part of their Smart Grid Deployment Plan, although how they will

[xii] The Federal Trade Commission enforces the Fair Credit Reporting Act (see http://www.ftc.gov/os/statutes/031224fcra.pdf), which includes the ability of consumers to sue for damages if data are improperly disclosed by a credit reporting agency. The Payment Card Industry Security Standards Council was formed by major credit card companies to develop standards in an effort to reduce public disclosure of credit card information (see https://www.pcisecuritystandards.org/index.shtml).

[xiii] As will be discussed in this chapter, there are several such guidelines from major national and international organizations. This particular stricture does not appear in the Fair Information Practice Principles published by the Federal Trade Commission and is often recommended for adoption related to regulation of the future grid.

analyze or approve such plans is not part of the rulemaking.[86] An appropriate function of the regulatory process is to balance the value of data collection with other concerns. In the utility industry, that regulatory process is still in its early stages.

An appropriate function of the regulatory process is to balance the value of data collection with other concerns.

Data Access, Use, and Disclosure

Information privacy ensures that owners of data have control over who can access and use those data. As a result, ownership, access, use, and disclosure of CEUD are linked issues requiring careful analysis. Indeed, in an analysis of industry and consumer group responses to its request for information about smart grid data access, third-party use, and privacy, DOE found that "a significant number of commenters believed that the issue of access was more critical to a discussion of Smart Grid privacy issues than the issue of data ownership."[87]

Electricity consumers can install measurement devices in their homes or businesses or on their appliances and other equipment and provide the data they collect to whomever they choose. However, less clear is the issue of ownership rights as it relates to data collected by electric utilities through smart meters or other devices owned by the utility. Utilities must have the ability to measure how much of their product they are supplying and to use that information to ensure the proper functioning of the grid and of their organizations. But do they have the right to know that a customer's TV was on for three hours on Tuesday evening if detailed measurement of electricity usage may tell them that? If not, then access, disclosure, or use of that type of information (which will certainly be available in the future, if not already) requires some type of regulation.

Electricity customers will demand, and should have, significant control over access to data about their electricity usage, both to supply third-party services they consider valuable and to restrict other usage that they consider detrimental.

The DOE analysis of industry and consumer group responses showed that while consumer-advocacy groups strongly supported customers' rights to control access to CEUD, utility respondents had a variety of views. Nonetheless, DOE concluded that "consumers should have some protection that utilities will not disclose CEUD to third parties unless given affirmative consent, that third parties should also be required to protect the privacy and security of CEUD they receive, [and] that various controls should be put in place."[88] This conclusion did not attempt to resolve the issue of ownership (which will vary across states) but rather focused directly on regulation of access, use, and disclosure. DOE also did not address the costs of implementing processes to deal with "affirmative consent," privacy, and other controls, nor did it address the potential concern of data use within the utility itself for marketing or other non-operational purposes.

Congress also is beginning to acknowledge the importance of laws governing CEUD data disclosure, although legislation has not yet been passed. For example, HR 4860, 2010's Electric Consumer Right to Know Act, died in committee but attempted to address these issues head-on, directing FERC to issue guidelines for minimum privacy standards.[89]

The important conclusion to draw from these various public and governmental discussions is that electricity customers will demand, and should have, significant control over access to data about their electricity usage, both to supply third-party services they consider valuable and to restrict other usage that they consider detrimental. The industry will need guidance via regulation on how to implement such customer control, and those regulations should provide a consistent framework across the U.S. It is then up to the utilities to apply proper information security techniques to ensure that these controls are implemented.

Regulating Privacy of Consumer Data

From a societal point of view, government has varying roles in providing protections to voluntary and involuntary business relationships. A relationship between a bank and its customers is voluntary, for example, and a customer could use evaluation of the bank's privacy policies and controls as a factor in choosing among competing banks. An electric utility customer, on the other hand, rarely has a choice of suppliers and thus is required to accept whatever policies that supplier discloses.[xiv] This puts an added burden on regulators to ensure that electric companies exercise prudence in creating and implementing plans for collecting, storing, and protecting consumer information.

Various parties have recommended that the Federal Trade Commission's Fair Information Practice Principles guide the development of regulation.[90] Forming the basis of existing laws in such sectors as credit reporting, financial information, electronic communications, and health information, these principles cover the following major topics:

- **Notice/Awareness:** "Consumers should be given notice of an entity's information practices before any personal information is collected from them."
- **Choice/Consent:** Consumers should have "options as to how any personal information collected from them may be used. Specifically, choice relates to secondary uses of information—i.e., uses beyond those necessary to complete the contemplated transaction. Such secondary uses can be internal, such as placing the consumer on the collecting company's mailing list in order to market additional products or promotions, or external, such as the transfer of information to third parties."
- **Access/Participation:** A consumer should be able "to access data about him or herself—i.e., to view the data in an entity's files—and to contest that data's accuracy and completeness."
- **Integrity/Security:** "Data should be accurate and secure."
- **Enforcement/Redress:** "It is generally agreed that the core principles of privacy protection can only be effective if there is a mechanism in place to enforce them."[91]

Other organizations, such as the American Institute of Certified Public Accountants,[92] the Canadian Standards Association,[93] and the Organisation for Economic Co-operation and Development[94] have created similar (but not identical) sets of principles that can provide additional guidance to the regulatory process.

One key question is who should regulate privacy of CEUD. DOE and FCC put this responsibility with individual states, but the circumstances of data generation and communication in the future grid may favor broader

[xiv] Note that electricity supply restructuring does not resolve this issue. Electricity customers may be able to choose the "generator" of their electricity, but they almost always have to deal with a single distributor—the utility that brings the electricity into the home or business and sends them the bill. The one exception is large industrial customer that may deal with more than one distributor.

action.[95] For example, municipal and cooperative electric utilities do not fall under either federal or state PUC jurisdiction in this regard. And data transmission across state lines (as shown in Figure 9.5) may complicate jurisdiction even for investor-owned utilities that are regulated by one or more state PUCs and by FERC. CEUD generated in a home or business may be transmitted to computer data centers owned or contracted by utilities that are in different states than the original source of the data. Similarly, they may be transmitted to third parties or government agencies in different states, either by the utility or the consumer themselves. As computer services and technology continue to advance to "the cloud,"

Regulating fundamental privacy principles now will ensure that data collection and storage systems do not have to be redesigned in the future and will help minimize the privacy challenges that may obstruct future grid projects.

where these services are provided by national or even international corporations with data centers in multiple jurisdictions, the likelihood of data crossing governmental boundaries becomes almost a certainty. As a result, a patchwork of individual state laws and regulations may not be the most effective or appropriate way to develop privacy and usage rules.

Regulating fundamental privacy principles now will ensure that data collection and storage systems do not have to be redesigned in the future and will help minimize the privacy challenges that may obstruct future grid projects. State PUCs are currently addressing these issues, and the North American Energy Standards Board in conjunction with the National Association of Regulatory Utility Commissioners and a dozen other organizations is preparing model business practices incorporating an analysis by NIST and other groups based on Fair Information Practice Principles. Non-regulated utilities should be encouraged to adopt these practices as well.[96]

FINDING

Maintaining appropriate control over electricity usage and related data is already and will remain an important issue with both residential and commercial consumers. Privacy concerns must be addressed to ensure the success of grid enhancement and expansion projects and the willingness of electricity consumers to be partners in these efforts.

Consumer Education

Studies, industry comments, and press reports alike show the need for ongoing consumer education about the impacts and benefits of future grid technologies, particularly in relation to metering and changes in billing practices. DOE makes the important statement that "consumer education and outreach to consumer advocates—some of whom still view advanced metering technologies with suspicion—will thus be critical components of efforts to promote the adoption of Smart Grid technologies."[97] The public increasingly is indicating the importance it attaches to information privacy issues, and this concern must be taken into account in any educational activities.[98] There appears to be broad agreement among industry and advocacy groups with this principle (although not necessarily with the specifics), as the EEI expresses: "Customers must be educated to understand the new privacy exposures presented by Smart Grid and be empowered to take steps to protect their privacy."[99]

9.4 CONCLUSIONS AND RECOMMENDATIONS

Data communications and cybersecurity technologies evolve rapidly and have life cycles much shorter than those of other electric grid components. The millions of communicating grid components likely to exist in the future will lead to a need for continuous transition among different models and versions of hardware and software. As a result, interoperability among new and legacy technologies will be an enduring challenge.

Additionally, we note the all-important role that education about cybersecurity and privacy issues will play in the development of the future grid, to disseminate practical information and counter incorrect information about these complex areas. These activities should be a part of general education about impacts and implications of new technologies and policies related to the future grid.

As described in this chapter, the successful integration of advanced data communications into electric grid control and operations will depend on utilities incorporating these new technologies and the extent of interoperability among different data communications technologies. Interoperability can be achieved through standardizing on specific technologies or protocols. The key trade-off is between early standardization (which may limit innovation) and late standardization (which may delay adoption and lead to future interoperability problems).

In the short run, NIST's facilitation of recommended standards will encourage market entry and facilitate interoperability. The Energy Independence and Security Act of 2007 gives FERC a role in "adopting" standards recommended by NIST, but it is unclear what the "adoption" of standards would mean in practice. As GAO recently reported, FERC currently does not have any way of monitoring industry compliance with standards it adopts through this process and, furthermore, only has authority over the bulk power system. Legislation may not be required but clarification would be helpful.

The fundamental question is how to ensure that innovation continues in and around the standardization process. The imposition of detailed federal standards beyond those that emerge from this process would not appear to be productive, although federal agencies, state PUCs, utilities, and consumer groups each have important roles to play as participants in the standard-setting process.

RECOMMENDATION

NIST and state PUCs should continue to work with industry's organic standardization processes to foster the adoption of interoperability standards. Toward this end, Congress should clarify FERC's role in adopting NIST-recommended standards as specified in the Energy Independence and Security Act of 2007 to ensure a smoothly functioning industry-government partnership.

Grid cybersecurity will require preparedness but also a heightened focus on detection, response, and recovery strategies, including strengthened testing and assessment processes. Assessments of electric grid systems conducted as part of industry or regulatory processes would provide added impetus for utility suppliers to ensure development of systems with sufficient concern for cybersecurity. As both cyberattacks and cybersecurity technologies evolve quickly, developing detailed cybersecurity standards will not entirely solve this problem. It is important to ensure that utilities, their suppliers, and third-party vendors all have a culture of consistent and continuous attention to cybersecurity challenges, and that the industry cooperates to disseminate assessment results to advance general cybersecurity in the electric sector.

Cybersecurity regulations for bulk power systems already exist in the form of the NERC Critical Infrastructure Protection reliability standards, but their scope is limited to the bulk power system and does not include the distribution system. Further, municipal distribution utilities and cooperatives are outside of the current regulatory environment. Public–private partnerships, such as the NIST Cyber Security Working Group, have made efforts to more comprehensively address grid cybersecurity but do not have regulatory authority. This lack of a single operational entity with responsibility for grid cybersecurity preparedness as well as response and recovery creates a security vulnerability in a highly interconnected electric power system comprising generation, transmission, and distribution.

RECOMMENDATION

The federal government should designate a single agency to have responsibility for working with industry and to have appropriate regulatory authority to enhance cybersecurity preparedness, response, and recovery across the electric power sector, including bulk power and distribution systems.

As noted above, the administration has proposed that DHS be the lead agency because of its broad multisector cybersecurity responsibilities, while proposals in Congress have focused on DOE and FERC because of their sector-specific expertise. Each agency has its strengths, and we do not feel qualified to choose between them. Once a lead agency has been designated, it should take all necessary steps to ensure that it has appropriate expertise by working with relevant federal agencies, NERC, state PUCs, public power authorities, and such expert organizations as the Institute of Electrical and Electronics Engineers and EPRI.

Expanded data collection and communications capabilities in the grid will result in a significant expansion of data about the electric grid system itself and of users of electricity. Maintaining appropriate control over electricity usage data is already and will remain an important issue with both residential and commercial consumers. Key societal concerns about information security and information privacy relate to access to and protection of information about grid operational data as well as consumer electricity usage data.

Industry and federal agencies have recommended that states establish regulations concerning privacy of CEUD, and the states are responding. However, we find that coordination of policy across states is necessary to mitigate concerns of companies that operate in multiple jurisdictions and of their customers as data on both companies and their customers cross state boundaries. Regulating fundamental privacy principles now will ensure that data collection and storage systems do not have to be redesigned in future, and will help minimize the privacy challenges that may obstruct future grid projects. State PUCs are currently addressing these issues, and the National Association of Regulatory Utility Commissioners and a dozen other organizations are preparing model business practices incorporating an analysis by NIST and other groups based on Fair Information Practice Principles. Non-regulated utilities should be encouraged to adopt these practices as well.

RECOMMENDATION

PUCs, in partnership with appropriate federal agencies, utilities, and consumer organizations, should focus on coordinating their activities to establish consistent privacy policies and process standards relating to consumer energy usage data as well as other data of importance to the operation of the future electric grid.

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Appendix A: A Brief History of the U.S. Grid[i]

Thomas Edison introduced the first electric power system in New York City in 1882. This direct current (dc) system initially served 59 customers in the Wall Street area at a price of about $5 per kilowatt hour (kWh).[ii] It operated at 100 volts and mainly supplied electric lights. By the end of the 1880s, many cities had similar small central stations that each served only a few city blocks.

To the extent that the industry was regulated, city governments performed this function. City governments also became major customers—for street lighting and trolley services—and could extract various concessions in exchange for the right to string wires. Soon, they also became owners. By 1900, municipally owned utilities accounted for about 8% of total U.S. generation. Vigorous debates about the relative merits of government- and investor-owned utilities continued in the U.S. through the 1930s, when federal policies were established that today still favor government-owned and cooperative utilities.

A.1 BEYOND MUNICIPAL BOUNDARIES

The transformer was first demonstrated at scale in Germany in 1891. This innovation enabled the use of relatively high-voltage transmission capable of carrying alternating current (ac) power over long distances with relatively low losses. In 1896, George Westinghouse began the hydroelectric development of Niagara Falls, transmitting significant power to Buffalo, New York, more than 20 miles away. This inaugurated the practice of locating generators at some distance from load centers and linking them by high-voltage transmission, then using transformers to lower the voltage delivered to ultimate customers.

Since then, engineering research and the development of new materials have enabled the use of ever-higher voltages. In the U.S., ac lines with voltages of up to 150 kilovolts (kV) were in place by 1910, and the first 245 kV line was commissioned in 1922. The invention of the transformer and high-voltage lines allowed private utilities to expand beyond municipal boundaries and take better advantage of economies of scale. Such expansion compounded problems with municipal regulation and led to state regulation of investor-owned electric utilities, generally with the utilities' active support. This trend began with the establishment of regulatory commissions in Wisconsin, Georgia, and New York in 1907. By 1914, 30 states had regulatory commissions, and today all states and the District of Columbia have them.[iii]

[i] Significant portions of Appendix A are taken from U.S. Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update* (Washington, DC: U.S. Department of Energy, 2000), http://www.eia.gov/cneaf/electricity/chg_stru_update/update2000.html; and Ignacio J. Perez-Arriaga, Hugh Rudnick, and Michel Rivier, "Electric Energy Systems—An Overview," in *Electric Energy Systems: Analysis and Operation*, ed. Antonio Gomez-Exposito, Antonio J. Conejo, and Claudio Canizares (Boca Raton: CRC Press, 2008), 1–50. See also David E. Nye, *Electrifying America* (Cambridge: MIT Press, 1990).

[ii] Except where otherwise noted, this price and others in Appendix A are expressed in 2010 dollars, using the Consumer Price Index from 1913 forward and the extension to earlier years available at http://www.measuringworth.org/datasets/uscpi/result.php/.

[iii] Nebraska's regulatory commission does not oversee electricity rates because no investor-owned utilities sell electricity in that state.

Vertically integrated, investor-owned firms—performing generation, transmission, and distribution as the sole provider within designated service areas—emerged as the dominant model. States enabled these firms to charge prices that allowed them to cover their costs.

Among those costs was a "fair" rate of return, determined by the commission, on the capital the utility had invested; this regime came to be known as "rate-of-return" regulation of electric and other utilities.

This evolution was politically rather than technologically determined. Because the U.S. political system was highly decentralized until at least the 1930s and most electric utilities operated within a single state, state regulation was the politically natural successor to supervision by municipal governments. In a different political context, in England local utilities were unable to expand for political reasons, and the system remained highly fragmented until a 1926 law mandated the establishment of an integrated nationwide grid.[1] In the U.S., due in part to strong faith in private enterprise over the first three decades of the 20th century, the relative importance of publicly owned utilities declined during this period.[2]

Between the turn of the century and the 1930s, electric utility capacity and generation grew at average rates of about 12% per year, doubling roughly every six years, despite a 14% drop in generation between 1929 and 1932. The efficiency of generators and transformers improved, and, as noted earlier, transmission voltages increased. Residential prices fell dramatically, from an average of about $4.30 per kWh at the turn of the century to $0.88 per kWh in 1932 (residential customers only).[3] Electricity was not yet universally available in 1932, but two-thirds of all homes already used it.

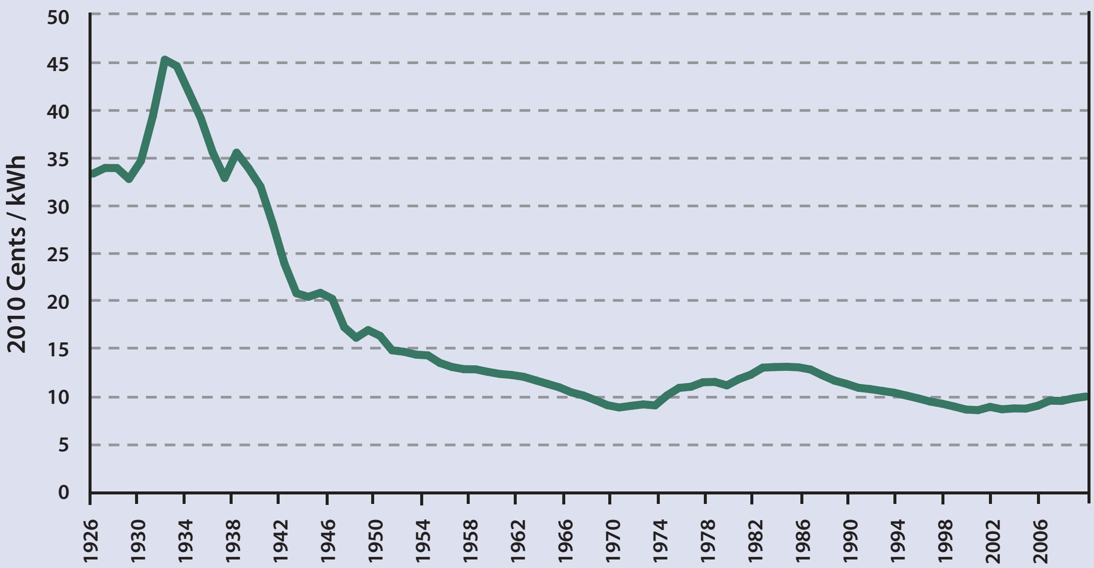
As Figure A.1 shows, average electricity prices across all customer classes continued to decline in real terms until fuel prices began increasing sharply following the first oil crisis in 1973. Between 1949 and 1973, electricity use grew at an annual average rate of 8.3%; it slowed to an annual average growth rate of 2.5% between 1973 and 2006 before declining slightly in 2007–2009.[4] Today, virtually all homes have grid-provided electricity, and the average retail price of electricity is approximately $0.10 per kWh over all classes of consumers.

A.2 A FEDERAL ROLE EMERGES

The federal role in the electric utility industry began in 1906, when legislation authorized the sale of surplus power from federal irrigation projects, giving sales preference to municipalities. Navigable waterways had been under federal jurisdiction since the early 19th century, and the Federal Water Power Act of 1920 both codified federal powers over navigable waterways and established the Federal Power Commission, later the Federal Energy Regulatory Commission (FERC), to issue hydroelectric power licenses.

During the Depression of the 1930s, confidence in unregulated markets waned, and after significant political struggles, the federal role in electric power was expanded dramatically under the New Deal. The Public Utility Holding Company Act of 1935 gave the Securities and Exchange Commission regulatory authority over utility holding companies and led to the dismantling of the largest companies, which had been constructed during the 1920s and associated with various stock market abuses. The Federal Power Act of 1935 empowered the Federal Power Commission to regulate the wholesale transmission and sale of electric power. The Rural Electrification Act of 1936 established the Rural Electrification

Figure A.1 U.S. Average Historical Electricity Prices (All Customer Classes)



Source: Data compiled from periodic statistical bulletins published by the Edison Electric Institute (formerly the National Electric Light Association). Historical prices expressed in 2010 cents using the Consumer Price Index.

Administration to provide loans and assistance to organizations (mainly rural electric cooperatives) that would provide electricity to rural areas instead of investor-owned utilities.

Also beginning in the 1930s, the federal government invested heavily in hydroelectric facilities on the waterways under its control and used these facilities to provide less expensive energy to "preferred customers": mainly municipal and cooperative utilities. Large Bureau of Reclamation dams—such as the Hoover Dam, which finished construction in 1936, and the Grand Coulee Dam, which finished construction in 1942—served the western states. Under the Tennessee Valley Authority Act of 1933, the federal government supplied hydroelectric power to states, counties, municipalities, and nonprofit cooperatives through its own corporation, the Tennessee Valley Authority. It was the largest electricity generator in the nation at the end of World War II. It now serves 9 million customers in most of Tennessee and parts of six adjacent states, and only about 10% of its production today comes from hydropower.[5]

Next, the federal government established the Bonneville Power Administration in 1937 to market low-cost power from the Bonneville Dam on the Columbia River. The Bonneville Power Administration now provides about 35% of the power in the Pacific Northwest and exports significant power to neighboring regions. It also controls about 75% of the high-voltage transmission lines in the Pacific Northwest.[6] Similarly, the Southwestern Power Administration and the Southeastern Power Administration were established in 1944 and 1950, respectively, to market low-cost federal power to preferred customers in designated regions.

By 1950, federal generation accounted for more than 12% of total U.S. generation.[7] Enthusiasm for expanding the federal role in the electric power sector declined after World War II, however, and this percentage has since fallen.

A.3 INTERCONNECTION AND COMPETITION

In the very early years of the industry, transmission was planned and built by vertically integrated utilities that met their native loads from their own generation. Even though interconnection promised to improve reliability, U.S. utilities were reluctant to interconnect and thus lose some control over their systems until pressed to do so during World War I.[8] Interconnection accelerated after the war, and in 1927 three major utilities established the PNJ Interconnection as a power pool linking transmission facilities in Pennsylvania, New Jersey, and Maryland that grew into the PJM regional transmission organization (RTO). Because different utilities often had standardized on different transmission voltages, mergers and interconnections between adjacent utilities often required—and often still require—transformers to link lines with different voltages. These transformers produce losses. Nonetheless, interconnection continued, and the Eastern Interconnection in its present form was established in 1962.

A major northeastern power blackout in 1965 raised concerns about the reliability of interconnected power networks. In response, the electric utility industry formed the North American Electric Reliability Council (NERC, later renamed the North American Electric Reliability Corporation) and its regional reliability councils to address the reliability and adequacy of the bulk power supply. NERC led the development and revision of reliability operating procedures for the grid. While compliance with these procedures was strongly encouraged, it was ultimately voluntary throughout most of NERC's history. The Energy Policy Act of 2005 and a subsequent FERC order paved the way for these procedures to be formalized into mandatory, enforceable standards. The current high degree of interconnection and the possibility of large-scale disruptions were dramatically demonstrated by the 2003 blackout, which spanned five independent system operator (ISO) regions (Midwest ISO, PJM, New York ISO, ISO New England, and Ontario's Independent Electricity Market Operator), as well as multiple independent control areas from Michigan to New Jersey.[9]

Despite these concerns, and to some extent in response to the Arab oil embargo, the federal government began opening the door to non-utility generation in the late 1970s in order to reduce dependence on foreign oil, promote alternative energy sources, and diversify the electric power supply. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which required regulated electric utilities to buy power from non-utility generators using cogeneration, renewable, or other designated technologies at the utility's "avoided cost" of generation, which it left to state regulators to determine. California and some other states determined that "avoided cost" was substantially above current costs and thereby encouraged the construction of substantial generation capacity that proved to be uneconomic. Subsequent legislation, particularly the Energy Policy Act of 1992, lowered barriers to the market entry of independent power producers, generators that have no legal obligation to provide power to ultimate customers, and utilities that could generate electricity for customers outside their service territories.

In the 1980s, a new model for power system organization began to emerge in the academic and policy literature.[10] In this model, organized competitive markets would set the price of wholesale electricity. Ownership of generation would often be separated from the rest of the system at least to some extent, and an independent entity would operate the transmission system and administer the wholesale markets. The provision of distribution services would remain a regulated monopoly, but there might be competition in the sale of electricity at retail. Overall, markets would perform some of the coordinating and cost-minimizing functions traditionally performed within vertically integrated utilities.

This new model had great appeal to some governments abroad that found themselves owning nationalized power systems that included generating plants that could be sold to raise revenue and to enable wholesale market competition. In 1982, Chile adopted a version of this new model, and in 1990, the Thatcher government in the United Kingdom followed suit as part of its privatization program. In the U.S., excess capacity in some regions as a result of slowing demand growth and overaggressive capacity expansion added to the attraction of this new model because it was presumed that competitive market prices for electricity would be below regulated prices.

To promote competition, in 1996 FERC used authority it was granted by the Energy Policy Act of 1992 to issue Order No. 888, which required transmission owners to provide open, non-discriminatory access to their systems to wholesale customers, under a regulated Open Access Transmission Tariff. The order effectively granted equal access to both utility and non-utility generators. FERC noted that one way to meet these requirements would be to have the regional transmission system operated by an ISO, an independent, federally regulated entity without generation or distribution assets.

Both Congress and FERC have repeatedly asserted that support of competitive wholesale electricity markets is national policy as part of a larger electricity restructuring effort intended to lead to a range of benefits.[11] FERC's Order No. 888 reflects an understanding that effective competition in wholesale markets requires open, non-discriminatory access to the transmission grid.[12] Rules for open transmission access necessarily include many of the critical elements of the broader design of wholesale electricity markets.[13] After many false starts and reforms of electricity markets, organized wholesale electricity markets operated by ISOs have come to share important common design elements.[14] Chief among these is reliance on the spot market or equivalent balancing framework with locational price differences that reflect generation and transmission costs. The International Energy Agency has described this model "as the benchmark for market design—the textbook ideal that should be the target for policy makers."[15]

In 1999, FERC issued Order No. 2000, which defined Regional Transmission Organizations (RTOs) as ISOs that have demonstrated to the FERC that they have satisfied a set of specified requirements. RTOs have slightly greater responsibilities than other ISOs for system reliability. Although Order No. 2000 strongly recommended that U.S. utilities affiliate with RTOs or ISOs, it did not require them to do so. Regionally, the Southeast and much of the West declined affiliation. The exceptions are California and Texas, which established single-state ISOs.

Where they have been established, RTOs or ISOs operate the wholesale market, dispatch generation to match load efficiently, and oversee the operation of the transmission system. They also generally are responsible for transmission system planning, a process that identifies and makes visible the need for strengthening the system to reduce costs and to maintain reliability. If necessary, the ISO or RTO can require transmission owners to make new capital investments. In this new structure, central control of generators' outputs is still necessary at all times in order to minimize system cost, satisfy reliability constraints, and respond to unexpected changes in load and other events. But now the cost to be minimized is the cost of buying power from independent generators in a wholesale market, at prices at which the generators are willing to supply. Competitive suppliers of new generating capacity play an important role in deciding what gets built and where. The detailed implementations of this new bulk power system structure have varied considerably over time and space, but they also have converged in important respects over time, and most observers agree that ISO/RTO systems have generally performed well.

At the retail level, most states were not eager to embrace competition. Nonetheless, 22 states and the District of Columbia did begin a variety of processes aimed at allowing competing vendors of electric power at the retail level, while continuing to treat the distribution of that power as a regulated monopoly.[iv]

California was a leader in the movement toward greater reliance on markets during the 1990s, with a wholesale market that began operation in 1998 and competing retailers allowed to enter in that same year. During 2000 and 2001, however, the California wholesale market experienced dramatic price increases and blackouts. The causes of this crisis involved a flawed market design, unusual shortage conditions in the western grid, illegal market manipulation on the part of some market participants, and inappropriate regulatory responses to emerging problems.[16]

This episode and the continued opposition of municipal and cooperative utilities, which benefit from a variety of subsidies and preferences put in place in the 1930s, have reduced political support for the new industry structure. Though the California ISO continues to operate, the state is no longer a leader in retail competition.[17] No new ISOs have been formed since this episode, though some existing ISOs have added affiliates. Movements toward retail competition have been suspended in seven states, and electricity price increases in some areas have led to calls to roll back prior reforms.[18]

In summary, the growth and evolution of the electric power industry since the dawn of electrification was determined by a multitude of different interacting factors. The industry's history is, in part, a story of continuous technical innovation. However, just as importantly, the pace and direction of change in the industry was also heavily influenced by shifting regulatory designs and policy priorities and the pace of economic growth. Finally, the evolution of the grid was also strongly shaped by unforeseen emergencies like the 1965 and 2003 blackouts and the California energy market crisis. Factors of all these sorts will continue to shape the evolution of the grid in the future.

[iv] State-by-state information on the history and status of vertical disintegration and retail competition efforts can be found at http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

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Appendix B: Electric Power System Basics

B.1 INTRODUCTION

Electricity is critical to our daily lives, yet most people have little understanding of the complex process that brings electric power to our homes, offices, and factories whenever we demand it. This appendix is a tutorial on how the electric power system works. We assume no prior knowledge in the area and start by providing a description of the physical foundations of electricity. We next discuss the structure and components of the electric power system. We follow with an explanation of how the system is operated and how wholesale electricity markets work. In the final section, we provide a brief overview of system planning. Because there are slight differences in the structure, operation, and planning of the electric power system from country to country and region to region, we focus mostly on fundamental aspects that remain unchanged; however, where appropriate we provide U.S.-centric details and highlight important variations in practice.

B.2 FUNDAMENTALS OF ELECTRIC POWER

To understand electric power systems, it is helpful to have a basic understanding of the fundamentals of electricity. These include the concepts of energy, voltage, current, direct current (dc), alternating current (ac), impedance, and power.[i]

Energy

Energy is the ability to perform work. Energy cannot be created or destroyed but can be converted from one form to another.[ii] For example, chemical energy in fossil fuels can be converted into electrical energy, and electrical energy in turn can be converted into useful work in the form of heat, light, and motion. While the scientific community measures energy in watt-seconds or joules, traditionally in the electric power industry, energy is measured in watt-hours (Wh) and for larger values is expressed in kilowatt (thousand watt, kW), megawatt (million watt, MW), gigawatt (billion watt, GW), or terawatt (trillion watt, TW) hours.[iii] A 100 watt lightbulb consumes 2,400 Wh (or 2.4 kWh) of energy in 24 hours, and the total annual electrical energy consumption of the U.S. in 2010 was about 3,900 TWh.[1] One kilowatt hour is equivalent to 3.6 megajoules.

Voltage

Voltage (also referred to as potential) is measured between two points and is a measure of the capacity of a device connected to those points to perform work per unit of charge that flows between those points. Voltage can be considered analogous to the pressure in a water pipe. Voltage is measured in volts (V), and for large values expressed in kilovolts (kV) or megavolts (MV).

[i] Those who only desire a high-level understanding of electric power systems can skip this section.

[ii] If mass is not considered a form of energy, an exception is in nuclear reactions, where mass and energy can be transformed into one another.

[iii] Watt is the unit of power, or the rate of flow (or consumption) of energy, as discussed later in this section.

Current

Current is a measure of the rate of flow of charge through a conductor. It is measured in amperes. Current can be considered analogous to the rate of flow of water through a pipe.

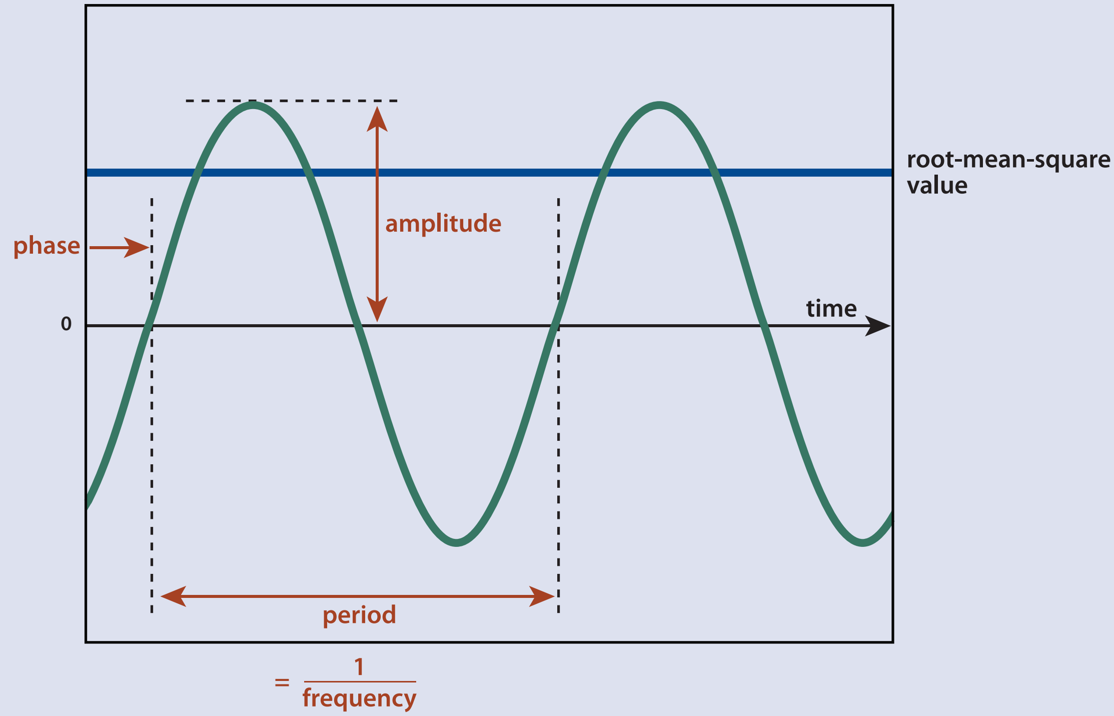
Dc and Ac

Current can be unidirectional, referred to as "direct current," or it can periodically reverse directions with time, in which case it is called "alternating current." Voltage also can be unipolar—in which one point is always at a higher voltage than the other—or alternating in polarity with time. Unipolar voltage is referred to as "dc voltage." Voltage that reverses polarity in a periodic fashion is referred to as "ac voltage." Alternating currents and voltages in power systems have nearly sinusoidal profiles.

Ac voltage and current waveforms are defined by three parameters: amplitude, frequency, and phase, as shown in Figure B.1. The maximum value of the waveform is referred to as its "amplitude." The amplitude of the ac voltage in a standard 120 V outlet is 170 V. The 120 V in this case refers to the root-mean-square (rms) value of the voltage and is the equivalent dc voltage with the capacity to perform the same amount of work. In the case of ac, the amplitude is equal to the rms value multiplied by the square root of two. In the case of dc, the amplitude and rms values are the same.

Frequency is the rate at which current and voltage in the system oscillate, or reverse direction and return. Frequency is measured in cycles per second, also called "hertz" (Hz). In the U.S., as well as the rest of North America and parts of South America and Japan, the ac system frequency is 60 Hz, while in the rest of the world it is 50 Hz.[2] Dc can be considered a special case of ac, one with frequency equal to zero.

Figure B.1 Amplitude, Frequency, Period, and Phase of an Alternating Current or Voltage Waveform



The time in seconds it takes for an ac waveform to complete one cycle, the inverse of frequency, is called the "period." The phase of an ac waveform is a measure of when the waveform crosses zero relative to some established time reference. Phase is expressed as a fraction of the ac cycle and measured in degrees (ranging from -180 to +180 degrees). There is no concept of phase in a dc system.

Electric power systems are predominantly ac, although a few select sections are dc. Ac is preferred because it allows voltage levels to be changed with ease using a transformer. The voltage level of a dc system also can be changed, but doing so requires more sophisticated and expensive equipment using power electronics technology. However, dc can be advantageous when energy has to be transmitted over long distances for reasons discussed later. Dc also is used to connect ac systems that operate at different frequencies (as in Japan) or systems with identical frequencies that are not synchronized (as between interconnections in the U.S.).[iv]

Impedance

Impedance is a property of a conducting device—for example, a transmission line—that represents the impediment it poses to the flow of current through it. The rate at which energy flows through a transmission line is limited by the line's impedance. Impedance has two components: resistance and reactance. Impedance, resistance, and reactance are all measured in ohms.

Resistance

Resistance is the property of a conducting device to resist the flow of ac or dc current through it. A transmission line is composed of wires known as "conductors" whose resistance increases with length and decreases with increasing conductor cross-sectional area. Resistance causes energy loss in the conductor as moving charges collide with the conductor's atoms and results in electrical energy being converted into heat. However, resistance does not introduce any phase shift between voltage and current. The rate of energy loss (called "power loss") is equal to the resistance times the square of the rms current.

Reactance

Voltages and currents create electric and magnetic fields, respectively, in which energy is stored. Reactance is a measure of the impediment to the flow of power caused by the creation of these fields. When the voltage and current are ac, this alternating storage and retrieval of energy retards the flow of power but no energy is lost. When energy is stored in magnetic fields, the element is said to have "inductive reactance," while "capacitive reactance" describes elements creating energy stored in electric fields. Reactance is a function of frequency—inductive reactance increases with frequency while capacitive reactance decreases. The presence of reactance in a system also creates a phase shift between voltage and current—inductive reactance causes the current to lag the voltage (a negative phase shift), while capacitive reactance forces the current to lead the voltage (a positive phase shift). (One way to visualize this is that the current is "busy" storing energy in a magnetic field as the voltage proceeds, while the voltage is "busy" storing it in an electric field as the current proceeds.)

The impedance of a transmission line is primarily comprised of inductive reactance. Therefore its current will be out of phase with and lag its voltage, which is undesirable for reasons discussed later. To compensate for this, elements with capacitive reactance (capacitors) are connected to the transmission line. The positive phase shift caused by these capacitors cancels out the negative shift due to the inductive

[iv] Synchronized systems are at the same frequency and have a specific phase difference between their voltages.

reactance of the transmission line and forces the transmission voltage and current to be in phase (a good thing). This process is called "line compensation."

The inductive reactance of a transmission line is proportional to both frequency and line length, and for long ac lines the inductive reactance limits the amount of power the line can carry. At zero frequency (dc) the reactance is zero, making dc attractive for long-distance transmission.

Power

Power is the rate at which energy is flowing or work is being done.[v] Since voltage is the amount of work done for each unit of charge that flows and current is the rate of flow of charge, the product of voltage and current is the rate of work—power, or more precisely instantaneous power. Since power loss is equal to the resistance of a conductor times the square of the current, loss in a transmission line can be reduced by increasing the transmission voltage, which allows the current to be reduced for the same amount of power transmitted. As a result, long transmission lines employ high voltage. However, as discussed later, high-voltage lines also have drawbacks, including the need to maintain larger clearances to maintain safety.

In ac systems, where voltage and current oscillate many times a second, the instantaneous power they produce is also rapidly varying, as shown in Figure B.2. In the figure, negative instantaneous power is equivalent to power flowing in the backwards direction. In electric power systems, it is more valuable to have measures of power that are averages over many cycles. These measures are real power, reactive power, and apparent power. Only two of these three measures are independent; apparent power can be determined from real power and reactive power.

Real Power

Real power, also called "active power" or "average power," is the average value of instantaneous power, as shown in Figure B.2, and is power that actually does work. It is measured in watts. Although instantaneous power can be flowing in both directions, real power only flows in one direction, as shown in Figure B.2(a)–(c). Real power is zero if the phase difference between voltage and current is 90 degrees, as shown in Figure B.2(d).

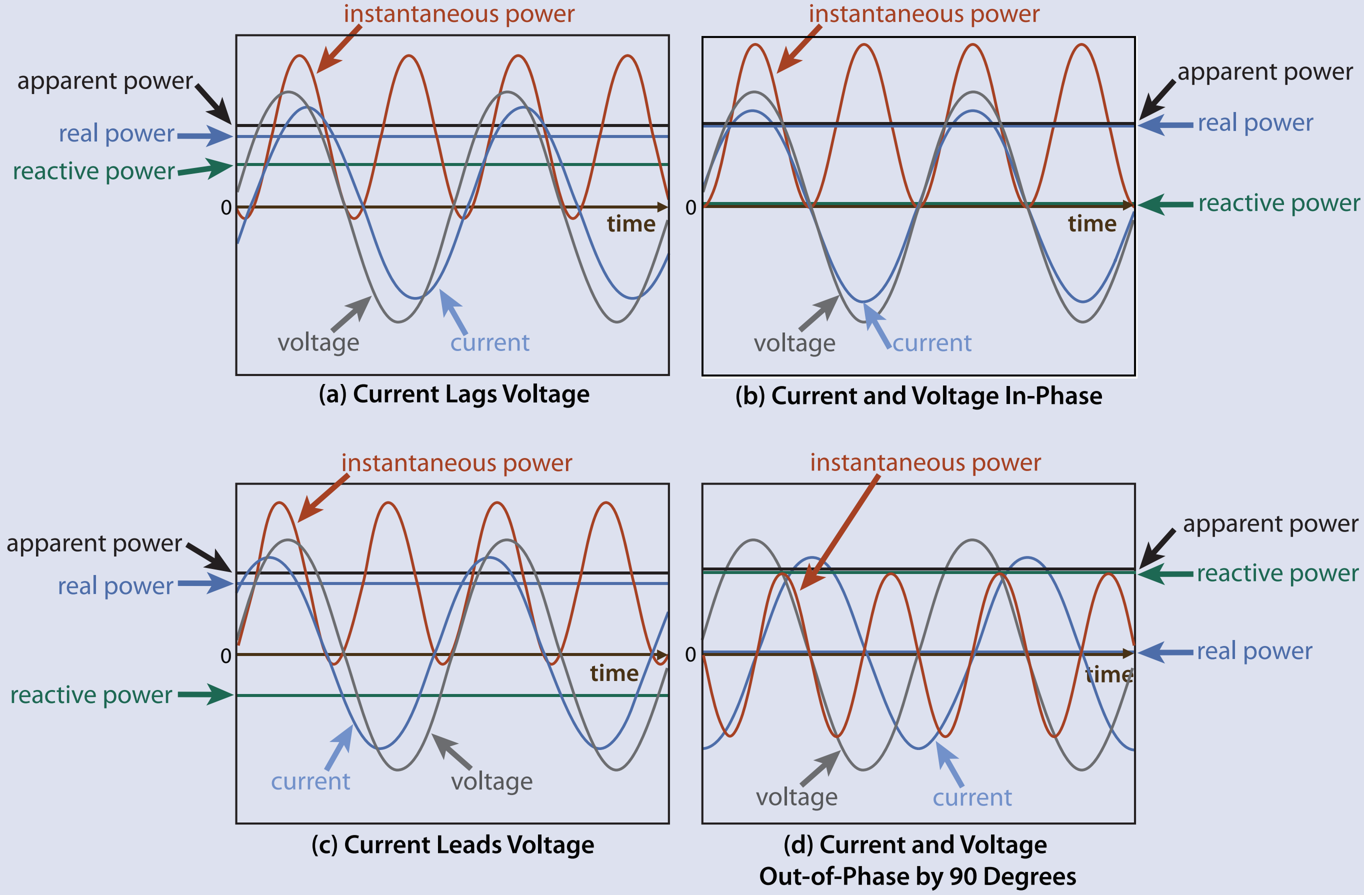
Reactive Power

If the voltage and current waveforms are "in phase"—that is, they cross zero at the same time—then instantaneous power, although varying, is always positive or flowing in one direction (Figure B.2(b)). In this case, all the power is real power. However, if one waveform is shifted in time relative to the other, a condition called "out of phase," then power takes on both positive and negative values, as shown in Figure B.2(a), (c), and (d). This phase difference can arise, for example, because of the reactance of the transmission line. Here, in addition to the real power that is flowing in one direction, there is back and forth movement of power called "reactive power." While it does no useful work, reactive power flow still causes power losses in the system because current is flowing through components, such as transformers and transmission lines, which have resistance. Reactive power is measured in volt-amperes reactive (VAR).

Reactive power can be positive or negative. But unlike instantaneous power, its sign does not indicate the direction of reactive power flow. Instead, the sign simply indicates the relative phase shift between current and voltage. When current lags voltage due to the presence of inductive reactance, reactive power is positive, as shown in Figure B.2(a); when current leads voltage due to the presence of capacitive

[v] It is energy that actually "flows" in a power system, power being the rate of this energy flow. However, though technically incorrect, common usage is to speak of "power flow."

Figure B.2 Current, Voltage, and Power in an Ac System



reactance, reactive power is negative, as shown in Figure B.2(c). Equipment that draws negative reactive power is often said to be "supplying" reactive power. In power systems, capacitors are often connected near large inductive loads to compensate for their positive reactive power.

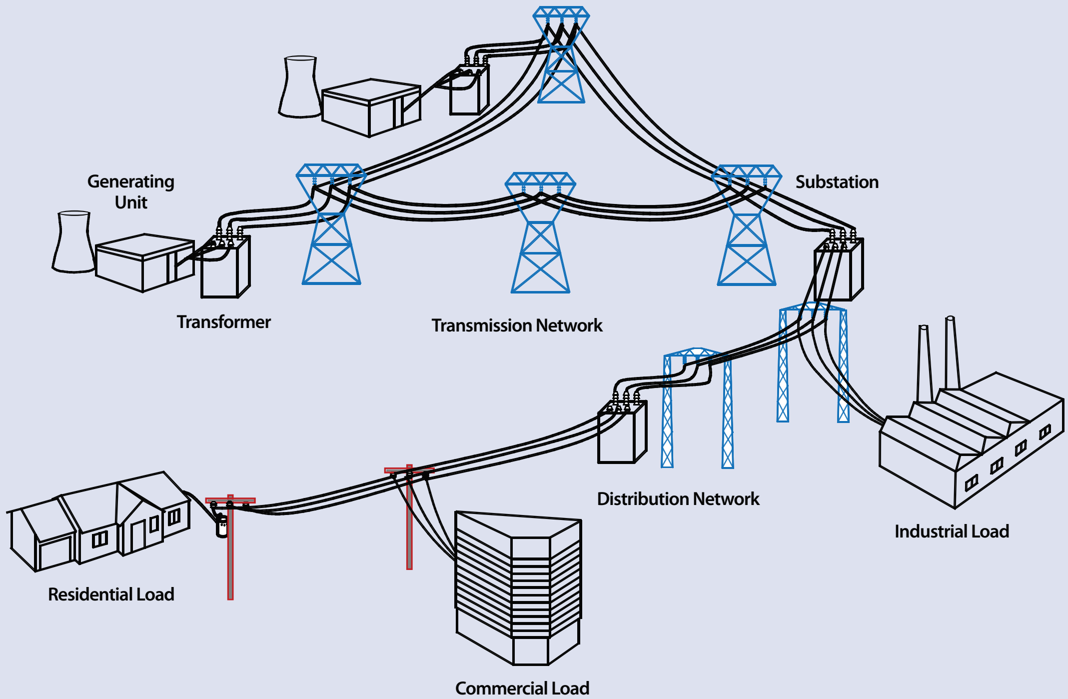
Apparent Power

Apparent power is the product of rms voltage and rms current, and is always greater than or equal to real and reactive power. Electrical equipment, such as transformers and transmission lines, must be thermally rated for the apparent power they process. Apparent power is measured in volt amperes. The ratio of real power to apparent power is called "power factor." Utilities like to maintain a unity power factor as it implies that all of the power that is flowing is doing useful work.

B.3 STRUCTURE OF THE ELECTRIC POWER SYSTEM

The electric power system consists of generating units where primary energy is converted into electric power, transmission and distribution networks that transport this power, and consumers' equipment (also called "loads") where power is used. While originally generation, transport, and consumption of electric power were local to relatively small geographic regions, today these regional systems are connected together by high-voltage transmission lines to form highly interconnected and complex systems that span wide areas. This interconnection allows economies of scale, better utilization of the most economical

Figure B.3 Structure of the Electric Power System



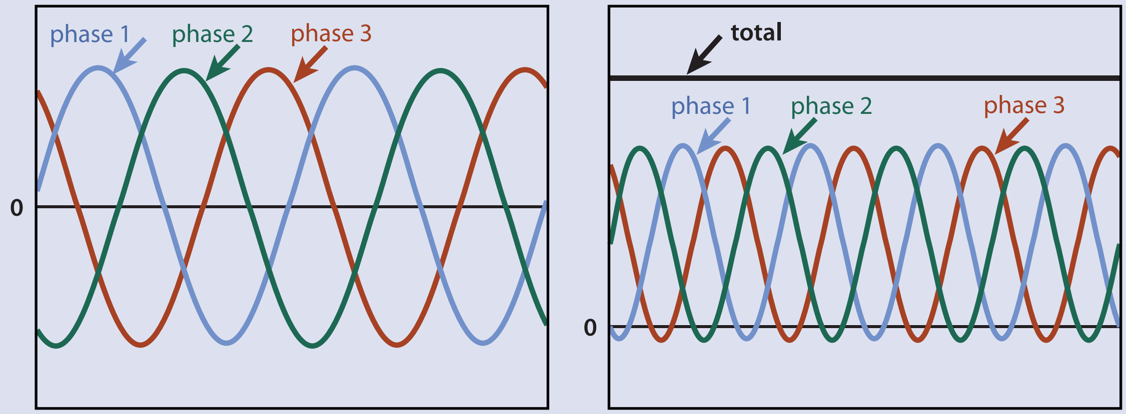
generators, increased reliability, and an improved ratio of average load to peak load due to load diversity, thus increasing capacity utilization. Interconnection also leads to complexity, however, as any disturbance in one part of the system can adversely impact the entire system. Figure B.3 illustrates the basic structure of the electric power system. We discuss each of its subsystems next.

Generation

Electric power is produced by generating units, housed in power plants, which convert primary energy into electric energy. Primary energy comes from a number of sources, such as fossil fuel and nuclear, hydro, wind, and solar power. The process used to convert this energy into electric energy depends on the design of the generating unit, which is partly dictated by the source of primary energy.

The term "thermal generation" commonly refers to generating units that burn fuel to convert chemical energy into thermal energy, which is then used to produce high-pressure steam. This steam then flows and drives the mechanical shaft of an ac electric generator that produces alternating voltage and current, or electric power, at its terminals. These generators have three terminals and produce three ac voltages, one at each terminal, which are 120 degrees out of phase with respect to each other, as shown in Figure B.4(a). This set of voltages is known as "three-phase ac voltage," whereas the voltage discussed in the previous section and illustrated in Figure B.1 is known as "single-phase ac voltage." Three-phase ac has multiple advantages over single-phase ac, including requiring less conducting material in the transmission lines and allowing the total instantaneous power flowing from the generator to be constant (Figure B.4(b)).

Figure B.4 Three-Phase System



(a) Voltage **(b) Instantaneous Power**

Nuclear generating units use an energy conversion process similar to thermal units, except the thermal energy needed to produce steam comes from nuclear reactions. Hydro and wind generating units convert the kinetic energy of water and wind, respectively, directly into rotation of the electric generator's mechanical shaft. Solar-thermal and geothermal generating units use the sun's radiation and the Earth's warmth, respectively, to heat a fluid and then follow a conversion process similar to thermal units. Solar photovoltaic generating units are quite different and convert the energy in solar radiation directly into electrical energy. Another common type of generating unit is the gas, or combustion, turbine. These burn a pressurized mixture of natural gas and air in a jet engine that drives the electric generator. Combined-cycle gas turbine plants have a gas turbine and a steam turbine. They reuse the waste heat from the gas turbine to generate steam for the steam turbine and hence achieve higher energy conversion efficiencies.[vi]

From the operational perspective of the electric power system, generating units are classified into three categories: baseload, intermediate, and peaking units. Baseload units are used to meet the constant, or base, power needs of the system. They run continuously throughout the year except when they have to be shut down for repair and maintenance. Therefore, they must be reliable and economical to operate. Because of their low fuel costs, nuclear and coal plants are generally used as baseload units, as are run-of-the-river hydroelectric plants. However, nuclear and coal baseload units are expensive to build and have slow ramp rates—that is, their output power can be changed only slowly (on the order of hours).

Intermediate units, also called cycling units, operate for extended periods of time but, unlike baseload units, not at one power continuously. They have the ability to vary their output more quickly than baseload units. Combined-cycle gas turbine plants and older thermal generating units generally are used as intermediate units.

Peaking units operate only when the system power demand is close to its peak. They have to be able to start and stop quickly, but they run only for a small number of hours in a year. Gas

[vi] Combined-cycle plants can have efficiencies in the 55%–60% range, compared to about 40% for conventional thermal plants.

turbine and hydroelectric plants with reservoirs are generally used as peaking units. Gas turbines are the least expensive to build but have high operating costs.

Large generating units generally are located outside densely populated areas, and the power they produce has to be transported to load centers. They produce three-phase ac voltage at the level of a few to a few tens of kV. To reduce power losses during onward transmission, this voltage is immediately converted to a few hundred kV using a transformer. All the generators on a single ac system are synchronized.

In addition to the main large generating units, the system typically also has some distributed generation, including combined heat and power units. These and other small generating units, such as small hydroelectric plants, generally operate at lower voltages and are connected at the distribution system level. Small generating units, such as solar photovoltaic arrays, may be single-phase.

Transmission

The transmission system carries electric power over long distances from the generating units to the distribution system. The transmission network is composed of power lines and stations/substations. Transmission system power lines, with rare exceptions, are attached to high towers. However, in cities, where real estate is valuable, transmission lines are sometimes made up of insulated cables buried underground. Stations and substations house transformers, switchgear, measurement instrumentation, and communication equipment. Transformers are used to change the level of the transmission voltage. Switchgear includes circuit breakers and other types of switches used to disconnect parts of the transmission network for system protection or maintenance. Measurement instrumentation collects voltage, current, and power data for monitoring, control, and metering purposes. Communication equipment transmits these data to control centers and also allows switchgear to be controlled remotely.

Since transmission networks carry power over long distances, the voltage at which they transmit power is high to reduce transmission losses, limit conductor cross-sectional area, and require narrower rights-of-way for a given power. However, to maintain safety, high transmission voltages require good insulation and large clearance from the ground, trees, and any structures. Transmission voltages vary from region to region and country to country. The transmission voltages commonly (but not exclusively) used in the U.S. are 138 kV, 230 kV, 345 kV, 500 kV, and 765 kV.[3] A voltage of 1,000 kV has been used on a transmission line in China. Although most transmission is three-phase ac, for very-long-distance transmission, HVDC can be beneficial because transmission lines present no reactive impedance to dc. HVDC also only requires two conductors instead of three. However, HVDC transmission lines require expensive converter stations (utilizing power electronics technology) at either end of the line to connect to the rest of the ac system.

Transformers at transmission substations convert transmission voltages down to lower levels to connect to the subtransmission network or directly to the distribution network. Subtransmission carries power over shorter distances than transmission and is typically used to connect the transmission network to multiple nearby relatively small distribution networks. In the U.S., the commonly used subtransmission voltages are 69 kV and 115 kV.

Topologically, the transmission and subtransmission line configurations are mesh networks (as opposed to radial), meaning there are multiple paths between any two points on the network. This redundancy allows the system to provide power to the loads even when a transmission line or a generating unit goes offline. Because of these multiple routes, however, the power flow path cannot be specified at will. Instead power flows along all paths from the generating unit to the load. The power flow through a particular transmission line depends on the line's impedance and the amplitude and phase of the voltages at its ends,[vii] as discussed in Box B.1. Predicting these flows requires substantial computing power and precise knowledge of network voltages and impedances, which are rarely known with high precision. Hence, precise prediction of the power flowing down a particular transmission line is difficult. The presence of multiple paths between generation and load in the transmission network also leads to flows on undesirable paths. These undesirable flows are known as "loop flows."

The power that can be transmitted on a transmission line is limited by either thermal, voltage stability, or transient stability constraints, depending on which is the most binding, as illustrated in Figure 2.4 in Chapter 2.[viii, 4] The thermal constraint arises due to the resistance of the transmission line that causes excessive power losses and hence heating of the line when the power flowing through it exceeds a certain level. The voltage stability constraint arises due to the reactance of a transmission line that causes the voltage at the far end of the line to drop below an allowable level (typically 95% of the nominal design voltage level) when the power flowing through the line exceeds a certain level. The transient stability constraint relates to the ability of the transmission line to deal with rapid changes in the power flowing through it without causing the generators to fall out of synchronism with each other. Generally, maximum power flow on short transmission lines is limited by thermal constraints, while power flow on longer transmission lines is limited by either voltage or transient stability constraints. These power flow constraints cause so-called congestion on transmission lines, when the excess capacity in the lowest-cost generating units cannot be supplied to loads due to the limited capacity of one or more transmission lines.

Some very large consumers take electric power directly from the transmission or subtransmission network. However, the majority of consumers get their power from the distribution network.

Distribution

Distribution networks carry power the last few miles from transmission or subtransmission to consumers. Power is carried in distribution networks through wires either on poles or, in many urban areas, underground. Distribution networks are distinguished from transmission networks by their voltage level and topology. Lower voltages are used in distribution networks, as lower voltages require less clearance. Typically lines up to 35 kV are considered part of the distribution network.

The connection between distribution networks and transmission or subtransmission occurs at distribution substations. Distribution substations have transformers to step voltage down to the primary distribution level (typically in the 4 to 35 kV range in the U.S.). Like transmission substations, distribution substations also have circuit breakers and monitoring equipment. However, distribution substations are generally less automated than transmission substations.

[vii] The power flow through a transmission line is roughly proportional to the phase difference between the voltages at its ends and inversely proportional to its impedance.

[viii] Power system stability limits also are discussed in Box 2.3 in Chapter 2.

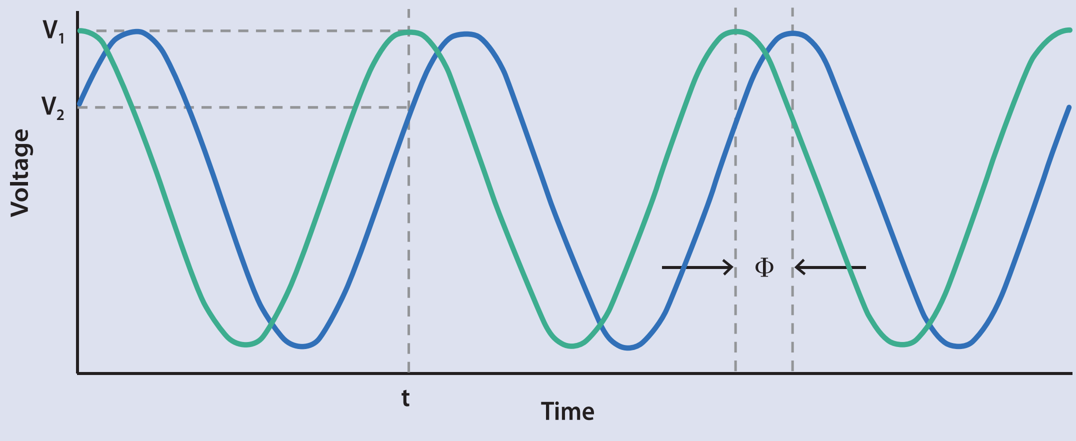
BOX B.1 CONTROLLING POWER FLOW

Two factors determine power flow: the impedance of a line and the difference in the instantaneous voltages at its two ends. Impedance is the combination of resistance and reactance. Resistance accounts for energy that is lost as heat in the line. It is analogous to the physical resistance exerted by water on a swimmer or wind on a cyclist. Energy lost in this way can never be recovered. Reactance accounts for energy associated with the electric and magnetic fields around the line. This energy is analogous to the potential energy stored when riding a bicycle up a hill. It is recovered (in the ideal case) when going down the other side. In an alternating current (ac) line in the U.S., this energy is stored and recovered 120 times per second, and thus is quite different from the behavior of energy stored in devices such as batteries. The resistance of a line is determined by the material properties, length, and cross-section of the conductor, while reactance is determined by geometric properties (the position of conductors relative to each other and ground). In practical transmission lines, resistance is small compared to reactance, and thus reactance has more influence on power flow than resistance.

As a function of time, the voltages at the ends of a transmission line are sinusoidal in shape. In the figure below, the two sinusoids represent voltages at opposite ends of a line. When there is power flow, the instantaneous values of voltage at the two ends of the line are different, as shown by the difference in voltages (V_1 and V_2) at time (t) in the figure. This instantaneous difference is a function of the difference in phase angle between the two sinusoids. The phase angle difference is shown in the figure as ϕ. If the two voltages are in phase, that is, if $\phi = 0$, then there will be no difference in their instantaneous values.

The power flow on a line varies directly with the phase angle difference (or more precisely the sine of the phase angle difference) and inversely with the line's impedance. Except in very special cases in which devices are used to control power flow on individual lines, the flow of power in a line is difficult to control when the line is part of an interconnected network since the characteristics of the entire network collectively determine power flows. When special devices are used to control power flow, they do so by modifying impedance and phase angle.

Phase Angle Difference (ϕ) of Voltage Sinusoids at the Ends of a Transmission Line



Primary distribution lines leaving distribution substations are called "feeders." They also carry three-phase ac voltage, which is why one sees three wires on many poles in rural and suburban areas. These individual phases are then separated and feed different neighborhoods.

Distribution networks usually have a radial topology, referred to as a "star network," with only one power flow path between the distribution substation and a particular load. Distribution networks sometimes have a ring (or loop) topology, with two power flow paths between the distribution substation and the load. However, these are still operated as star networks by keeping a circuit breaker open. In highly dense urban settings, distribution networks also may have a mesh network topology, which may be operated as an active mesh network or a star network. The presence of multiple power flow paths in ring and mesh distribution networks allows a load to be serviced through an alternate path by opening and closing appropriate circuit breakers when there is a problem in the original path. When this process is carried out automatically, it is often referred to as "self-healing." Distribution networks usually are designed assuming power flow is in one direction. However, the addition of large amounts of distributed generation may make this assumption questionable and require changes in design practices.

Industrial and large commercial users usually get three-phase supply directly from the primary distribution feeder, as they have their own transformers and in certain cases can directly utilize the higher voltages. However, for the remaining consumers, who generally require only single-phase power, power is usually transmitted for the last half-mile or so over lateral feeders that carry one phase. A distribution transformer, typically mounted on a pole or located underground near the customer, steps this voltage down to the secondary distribution level, which is safe enough for use by general consumers. Most residential power consumption in the U.S. occurs at 120 V or 240 V. In suburban neighborhoods, one distribution transformer serves several houses.

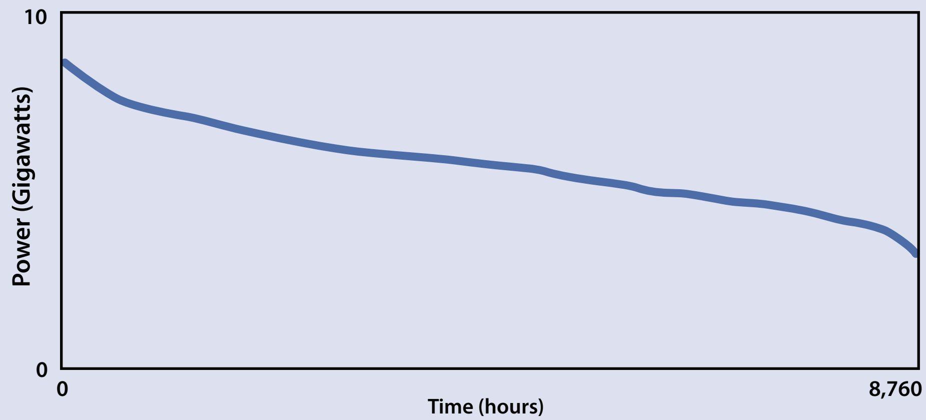
Consumption

Electricity is consumed by a wide variety of loads, including lights, heaters, electronic equipment, household appliances, and motors that drive fans, pumps, and compressors. These loads can be classified based on their impedance, which can be resistive, reactive, or a combination of the two. In theory, loads can be purely reactive, and their reactance can be either inductive or capacitive. However, in practice the impedance of most loads is either purely resistive or a combination of resistive and inductive reactance. Heaters and incandescent lamps have purely resistive impedance, while motors have impedance that is resistive and inductive. Purely resistive loads only consume real power. Loads with inductive impedance also draw reactive power. Loads with capacitive impedance supply reactive power.

Because of the abundance of motors connected to the network, the power system is dominated by inductive loads. Hence, generating units have to supply both real and reactive power. Since capacitors produce reactive power, they often are connected close to large inductive loads to cancel their reactive power (i.e., increase the effective power factor of the load) and reduce the burden on the network and the generators.

From the power system's operational perspective, the aggregate power demand of the loads in a region is more important than the power consumption of individual loads. This aggregate load is continuously varying. A useful representation of this load across the year is the load duration curve, which plots the load for each hour of the year, not chronologically, but instead by beginning with the hour with the

Figure B.5 A Load Duration Curve



largest load and continuing in a monotonically decreasing fashion, as shown in Figure B.5. For each point on this curve, the horizontal coordinate is the number of hours in the year for which the load is above the power given by the vertical coordinate. The load duration curve provides a good picture of how widely the load varies and for how many hours in a year it is above a particular level. It is more expensive to meet the needs of a spiked load duration curve than a flat one, as generation capacity to meet the peak load is needed, while the generation's utilization is related to the average load. One useful metric of power consumption is the load factor, which is the ratio of average to peak load.

B.4 OPERATION OF THE ELECTRIC POWER SYSTEM

The electric power system is operated through a combination of automated control and actions that require direct human (system operator) intervention. The main challenge in operating the electric power system is that there is negligible "electrical" storage in the system.[ix] Hence, supply and consumption of electrical power must be balanced at all times. Since the load is changing all the time in ways that cannot be perfectly predicted, generation must follow the load in real time. The balance between supply and demand is maintained using a hierarchical control scheme, with crude matching at the longer timescale and finer matching at the shortest timescale (see Figure 2.1 in Chapter 2).[5]

Protection

An important aspect of the operation of the electric power system is protection. This means ensuring the safety of the system, including generating units and other grid assets, and the people who may come in contact with the system. Protective action must be taken in fractions of a second to avoid equipment damage and human injury. Protection is achieved using sensing equipment as well as circuit breakers and other types of switches that can disconnect and de-energize parts of the system in the case of a fault, such as a damaged transmission line or a short circuit. Once the fault is repaired, that segment of the system can be brought back online.

[ix] Note that pumped storage, which uses electricity to pump water into an elevated reservoir and stores energy in the form of potential energy, is not a form of electrical storage. A hydroelectric generating unit must be run to convert this energy back into electrical form. Energy storage technologies are discussed in Chapter 3.

Proactive planning for contingencies also protects the electric power system. Computers are regularly calculating system power flows and voltages under various possible contingencies, for example the failure of a large generator or transmission line, to identify the best corrective action to take in each case.

Real-time Operation

The objective of real-time operation of the electric power system is to ensure that the system remains stable and protected while meeting end user power requirements. This requires a precise balance between power generation and consumption at all times. If this balance is not maintained the system can become unstable—its voltage and frequency can exceed allowable bounds—and result in damaged equipment as well as blackouts. If the balance is not restored sufficiently quickly, a local blackout can grow into a cascading blackout similar to the ones in the U.S. in 1965 and 2003. Fortunately, the stored kinetic energy associated with the inertia of generators and motors connected to the system helps overcome small imbalances in power and this "ride-through" capability gives enough time for an active control system to take corrective action. The balance between supply and demand at the shortest timescale is maintained actively via governor control.

Governor Control

As the load and/or generation changes, altering the balance between demand and supply, the generators on governor control take the first corrective action. The governor is a device that controls the mechanical power driving the generator via the valve limiting the amount of steam, water, or gas flowing to the turbine. The governor acts in response to locally measured changes in the generator's output frequency from the established system standard, which is 60 Hz in the U.S.[x]

If the electrical load on the generator is greater than the mechanical power driving it, the generator maintains power balance by converting some of its kinetic energy into extra output power—but slows down in the process. On the other hand, if the electrical load is less than the mechanical power driving the generator, the generator absorbs the extra energy as kinetic energy and speeds up. This behavior is known as "inertial response." The frequency of the ac voltage produced by the generator is proportional to its rotational speed. Therefore, changes in generator rotational speed are tracked by the generator's output frequency. A decreasing frequency is an indication of real power consumption being greater than generation, while an increasing frequency indicates generation exceeding power consumption. Any changes in frequency are sensed within a fraction of a second, and the governor responds within seconds by altering the position of the valve—increasing or reducing the flow to the turbine. If the frequency is decreasing, the valve will be opened further to increase the flow and provide more mechanical power to the turbine, hence increasing the generator's output power, bringing demand and supply in balance and stabilizing the speed of the generator at this reduced level. The speed of the generator will stay constant at this level as long as the mechanical power driving it balances its electrical load. While very fast, for stability reasons, governor control is not designed to bring the frequency of the generator back to exactly 60 Hz. Correcting this error in frequency is the job of the slower automatic generation control (AGC), discussed later in this section.

Voltage Control

Just as an imbalance in supply and demand of real power causes a change in system frequency, an imbalance in supply and demand of reactive power causes a change in system voltages. If the reactive power consumed by the load increases

[x] The generator's output frequency is proportional to its rotational speed, and traditionally governors have been designed to sense this speed.

without a commensurate increase in reactive power supply, the output voltage of the generator will decrease. Conversely, the output voltage of the generator will increase if the generator is supplying more reactive power than is being drawn. The voltage can be restored to its original level by either adjusting the generator's rotor current (which controls the amount of reactive power produced by the generator), or by using ancillary voltage support equipment, such as static VAR compensators that employ inductors and capacitors in conjunction with semiconductor switches to absorb or supply the imbalance in reactive power. Voltage control is also extremely fast.

Automatic Generation Control

While governor control brings supply of and demand for real power in balance, it results in a small change in system frequency. Furthermore, governor-based reaction of generators located outside a control area to load changes inside the control area (or vice versa) can alter power flows between control areas from their scheduled levels.[xi] The errors in frequency and flows between control areas are corrected by the relatively slower AGC. AGC aims to eliminate the area control error (ACE). ACE is a measure of both the difference between actual and scheduled net power flows to or from a control area and the error in system frequency. Ignoring the effect of system frequency, a positive ACE means that generation within the area exceeds load by more than the scheduled net power flow from the control area. In this case, the generation in the control area needs to be reduced. Conversely, negative ACE requires local generation to be increased. The area control center automatically sends signals to generators equipped with AGC to increase or decrease their output. In exceptional circumstances, when the required change in output is greater than the defined limit of AGC, the system operator can call the generation operator over the phone and ask for an increase or decrease in output.

Reserves

Beyond a certain level of power imbalance, system operators need to call in generation reserves. These may be additional generating units that are on standby or generators that are already producing power but can ramp up their output on request. Having adequate reserves on the system is essential to deal with load uncertainties and contingencies, such as the failure of a generating unit.

Reserves are categorized based on the time it takes them to start delivering the requested power; typical categories are 10-minute and 30-minute reserves. Reserves can be either spinning or non-spinning. Spinning reserves are generating units with turbines spinning in synchronicity with the grid's frequency without supplying power. They can deliver the requested power within a few minutes. Non-spinning reserves are units that are offline but also can be synchronized with the grid quickly. In systems with organized markets, reserves are paid not only for the energy they produce but also for being available on short notice to deliver reserve power.

Other Power Balancing Options

Large customers in some regions often face real-time pricing, which induces them to cut loads when the system is under stress and the real-time incremental cost of supplying power is accordingly high. However, when all other options for balancing power have been exhausted, the system operator must resort to proactively reducing the load, generally referred to as load shedding. Load shedding can be accomplished in a number ways. At first the system operator can interrupt power to those

[xi] From an operational perspective, a large electric power system is divided into multiple control areas, also called "balancing authority areas." These control areas are connected together via transmission lines that are called "tie-lines."

loads with which they have contracts that permit this. Alternatively, the system operator can order voltage reductions, also known as brownouts. Many loads, such as heaters, incandescent lamps, and certain types of motors, consume less power (and do less work) when operated on a lower voltage. Hence, by reducing the voltage supplied to the loads, the total system power consumption can be reduced. If neither method achieves the desired reduction in load, the system operator can initiate rotating blackouts. In rotating blackouts, groups of consumers are disconnected one at a time in a rotating fashion for a certain fixed duration (typically one hour). This disconnection is typically carried out by opening switches at the distribution substations.

Scheduling

Scheduling determines which generating units should operate and at what power level, and it is accomplished on a predetermined, fixed time interval. The objective is to minimize cost, subject to generation and transmission constraints. Scheduling consists of economic dispatch and unit commitment, each covering two overlapping time ranges.

Economic Dispatch

The incremental production costs of generating units can be quite different from one another, mostly due to differences in the costs of their "fuel" (for example, uranium, coal, natural gas) and their efficiencies. Economic dispatch minimizes overall production costs by optimally allocating projected demand to generating units that are online. Computers at control centers run optimization algorithms, typically every 5 or 10 minutes, to determine the dispatch for the next hour and send these economic dispatch signals to all the generators. Sometimes power cannot be dispatched from the lowest-cost generating unit due to physical limits of the system or security constraints associated with maintaining secure operation under contingencies. Physical restrictions include transmission lines' thermal and stability constraints and limitations on generating units' output power and ramp rates. Security constraints include transmission line reserve capacity and generation reserve requirements. Economic dispatch optimization subject to security constraints is known as "security-constrained economic dispatch."

Unit Commitment

In addition to determining the amount of power each generating unit should be producing when it is online, system operators must also determine when each generating unit should start up and shut down. This function is known as "unit commitment." Although significant costs are associated with the startup and shutdown of generating units, it is not practical to keep all of them online all the time. There are large fixed costs associated with running generating units, and some units have a minimum power they must produce when they are online. Unit commitment determines the economically optimal time when generating units should start up and shut down and how much power they should produce while they are online. This optimization is more complex and time consuming than economic dispatch. Unit commitment is typically done one day ahead and covers dispatch for periods ranging from one to seven days.

B.5 WHOLESALE ELECTRICITY MARKETS

The organizational structure of the electric power industry has changed significantly over the last 15 years, as discussed in Chapter 1. Until the mid-1990s, the electric power industry in the U.S. mostly was vertically integrated: a single entity, a regulated monopoly, owned and operated generation, transmission, and distribution in each region.[xii] However, in 1996 the Federal Energy Regulatory Commission issued Order No. 888, which required that the transmission network be made available for use by any generator. Since then independent system operators (ISOs) and regional transmission organizations (RTOs) have been created in certain parts of the US. In many regions, ownership of generation and transmission have been separated. In regions where they exist, ISOs and RTOs coordinate organized wholesale electricity markets in which independent decisions of market participants (those who buy and sell energy or other electricity market products, such as spinning reserves) set the price of energy generation, respecting the requirements of central coordination provided by the ISO or RTO.

The theory of spot pricing provides the foundations for successful market design.[6] In a framework known as "bid-based, security-constrained, economic dispatch," central coordination by the system operator is integrated with decentralized decisions by market participants. The process of selling wholesale energy begins with a bidding process whereby generators offer an amount of energy for sale during specific periods of the day next day at a specific price. These offers are arranged by the ISO/RTO in ascending order, called the "bid stack," and the generators are dispatched (told to generate) in this order until generation matches expected load. (Large loads also sometimes submit bids for the purchase of energy in the market.) All the dispatched generators receive the same compensation, called the "clearing price"—the offer of the last generator dispatched. The actual process is more complicated than this simple explanation, incorporating such parameters as the time required to start generators, out-of-economic-order dispatch due to congestion or reliability concerns, and security constraints. The goal of the system operator is to determine the dispatch that minimizes total cost, as measured by generators' bids, subject to security constraints.

This process determines the marginal cost of meeting an increment of load at each location (called a "node") in the transmission system to which load or generation is connected. These costs are termed "locational marginal prices" (LMPs) and are the prices at which transactions for purchasing or selling energy in the market take place. Distribution companies or large customers pay the applicable LMP for energy consumed. Similarly, generation is paid the LMP at the point at which it is located.

The LMP pricing structure used in modern markets ensures that the profitable choice for generators and loads is to follow the instructions of the economic dispatch. Generators are only dispatched when their offer to sell is at a price no greater than the market-clearing price at their location. Likewise, generators are not dispatched when the market price is less than their offer to sell. The use of LMPs allows for the preservation of the traditional industry approach of security-constrained, economic dispatch in the presence of independent system operators and organized wholesale markets. The use of LMPs exploits the natural definition of an efficient equilibrium for a market, utilizes the unavoidable central coordination, and avoids the need for market participants to track transmission flows or understand the many constraints and requirements of the power system.

[xii] The exceptions were small municipal and cooperative entities that were distribution-only operations and, particularly from the 1930s on, federal systems such as the Tennessee Valley Authority.

B.6 POWER SYSTEM PLANNING

Construction of new generating units and transmission lines requires large investments and significant time (ranging from a few years to a decade). Hence, planning of electrical power system expansion requires careful analysis that relies on long-term demand forecasts of 10 to 20 years. Projecting demand accurately over the long term is challenging and requires consideration of a number of factors, including estimates of population growth, historic individual consumption patterns, and projected economic growth. Long-term demand forecasts also may incorporate the projected impacts of new energy conservation and demand response programs.

In regions served by vertically integrated utilities, generation and transmission expansion planning is carried out centrally by system planners at the utilities. Planners evaluate various options for meeting future load demand in terms of capital and operating costs. They select projects based on minimizing system cost while providing adequately reliable service. Decisions also may be influenced by government incentives, regulations, and environmental impact restrictions. Planning has to allow for the risk associated with the significant uncertainty in long-term load forecasts, future operating costs (directly related to fuel prices), and technological changes.

In regions with organized wholesale markets, expansion planning is split between ISOs/RTOs and the individual market players. Generation planning is decentralized and primarily accomplished by individual generation companies based on forecasts and system needs from the RTO/ISO. Transmission planning is still mostly centralized and coordinated by ISOs/RTOs. While the precise mechanism by which expansion projects are selected depends on market design details, individual company decisions are based on maximizing return on investment. However, the competitive nature of the market is expected to lead to an overall system cost minimization while providing stronger incentives for operating efficiencies.

An added complexity in planning future transmission expansion in areas with organized markets is the uncertainty associated with future generation investments. Transmission expansion decisions are more challenging for ISOs/RTOs because development of generating plants is based on individual company decisions. As a result, the ISOs/RTOs cannot know the location and size of these future plants with certainty.

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Glossary

admittance	The ratio of current to voltage, including the effects of both resistance and reactance; the inverse of impedance.
advanced metering infrastructure (AMI)	A system for measuring individual customers' electricity consumption at intervals of an hour or less and communicating that information at frequent intervals to the distribution utility.
alternating current (ac)	An electric current that reverses direction at regular intervals and is the dominant form of electric power in transmission and distribution systems worldwide.
ampere	A measure of the amount of electric charge passing a point in an electric circuit per unit time.
ancillary services	Services, such as spinning reserves, non-spinning reserves, and regulation, that support the transmission of energy from generating resources to loads while maintaining reliable operation of the network.
attack vector	A path or means by which an attack can be or is made on critical infrastructure.
automatic generation control (AGC)	An automatic system to vary mechanical input to a generator to match small variations in system load.
balancing authority	An entity responsible for balancing generation and load (with specified imports and exports) within a specified geographic region.
bandwidth	Broadly, the amount of information that can be communicated through a given communications channel per unit time. Alternatively, the range of radio frequencies in a given radio channel (spectrum).
battery electric vehicle (BEV)	A vehicle that operates solely with electric power provided by batteries.
bulk power system	That part of the electric grid comprised of generators and high-voltage transmission lines.
capacitance	A parameter relating the charge stored in an electric field to the voltage producing the field. Transmission lines have capacitance because their voltage creates electric fields between conductors and between conductors and the ground.
capacitor	An element exhibiting capacitance.
capacity market	A wholesale forward market for resources to supply energy. These capacity resources are usually, but not always, generators. *See "capacity market demand response programs."*
capacity market demand response programs	Wholesale forward market programs in which customers bid future load reductions as system "capacity" to replace procurement of conventional generation or delivery resources, usually in exchange for upfront capacity payments.
congestion	A condition that occurs when lack of transmission capacity prevents the least-cost set of generators from serving load, causing an increase in the wholesale price of electricity or cost of service at one or more locations in the system.
contingency	An abnormal event in the power system, such as the tripping of a generator or a transmission line.
converter	A generic term referring to a system employing power electronics to convert electrical energy from one form to another, e.g., from direct current at one voltage to direct current at another voltage or alternating current at one frequency to direct current or to alternating current at another frequency.

critical peak pricing	A dynamic pricing plan that combines peak/off-peak time-of-use rates with substantially higher "super-peak" rates that apply only to peak hours on a limited number of critical days during the year. Critical days typically are announced the day before, on the basis of forecast market conditions.
current	The amount of electric charge flowing past a specified circuit point per unit of time.
demand response	Customer loads that are responsive to conditions in the electric power system, particularly at peak times.
direct current (dc)	An electric current that flows in one direction and is used selectively in electric power systems, primarily for point-to-point applications.
distributed generation (DG)	Small-scale, on-site generation systems owned by entities that are primarily consumers of electricity.
distribution automation	The application of advanced technology to automate the maintenance, control, and operation of the distribution network.
distribution primary voltage	The voltage at which power is distributed before the final step-down transformer to customer delivery voltage (typically 13.8 kilovolts, but can range from as low as 2 kilovolts to as high as 34.5 kilovolts).
distribution system	The part of the power system that delivers electricity to customers, operating at lower voltages than the transmission system.
dynamic line rating (DLR)	Line rating determined by the current ambient conditions, such as temperature and wind speed.
dynamic pricing	A regime in which retail customers face energy prices that vary with the contemporaneous cost of generation or state of supply-and-demand conditions in the electric power system. Prices may be based on day-ahead or hour-ahead forecasts of conditions, and may change for as few as 60 "critical peak" hours per year, or may change hourly or more often in real-time pricing plans.
Eastern Interconnection	One of the two major synchronized alternating current power grids in North America, reaching from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida, and back west to the foot of the Rockies (excluding most of Texas).
economic dispatch	The assignment of generating units' production in order to minimize overall costs.
electric vehicle (EV)	A vehicle that operates with electric power provided by batteries. EVs include both plug-in hybrid electric vehicles and battery electric vehicles but do not include hybrid electric vehicles, which are self-powered and never connected to the electric grid.
Electric Reliability Council of Texas (ERCOT)	Synchronized alternating current power grid that occupies nearly all the state of Texas.
extra-high voltage	Transmission voltages between about 345 kilovolts and 765 kilovolts.
fault	On a transmission or distribution line, an abnormal flow of electric current, e.g., an open circuit (an interruption in the flow) or a short circuit (a flow that bypasses the normal load).
fault current limiter (FCL)	A device that limits line current from faults to some pre-determined level.
Federal Energy Regulatory Commission (FERC)	U.S. independent agency that: regulates the interstate transmission of electricity, natural gas, and oil; reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines; licenses hydropower projects; and performs some other related activities.
feed-in tariff	A fixed price paid for electricity generated from specified renewable technologies.

flexible alternating current transmission system (FACTS)	A set of technologies employing power electronics that enable control of various transmission system operating parameters, including volt-ampere-reactive support and power flow.
generation	The process of converting energy from some other form into electricity, usually in power plants, but also via distributed generators, such as solar photovoltaic arrays.
generator	A device that transforms some other form of energy (typically mechanical energy) into electrical energy.
grid	The physical components of the electric power system that link generating units to the loads they serve, as well as the associated operational, regulatory, and governance structures.
harmonic distortion	The deviation of a waveform from a pure sinusoidal shape caused by the addition of frequencies other than 60 hertz.
high-temperature super conductor (HTSC)	A material with resistance that becomes very low (but not zero) when cooled to temperatures at or somewhat below that of liquid nitrogen (77 Kelvin).
high-voltage direct current (HVDC)	Technologies for transmitting bulk power via direct current at transmission-level voltages.
impedance	The opposition of a conducting device to the flow of alternating current through it; the inverse of adminttance. The impedance of an element depends on its reactance in addition to its resistance.
independent power producer	An entity that is not a public utility and that owns facilities to generate electricity for sale to utilities and/or end users.
independent system operator (ISO)	A regulated entity without generation or distribution assets that oversees the wholesale electricity market and operates the bulk power system in a particular region.
inductance	A parameter relating energy stored in a magnetic field to the current producing the field. Transmission lines have inductance because their current creates magnetic fields around their conductors.
inductor	An element exhibiting inductance.
inertia	The resistance of any physical object to a change in its state of motion (or rest). Inertia is proportional to mass; inertia in generators and loads enhances the stability of an electric power system.
inverter	A power electronic system whose function is to convert electric power from direct current to alternating current.
line rating	Maximum steady-state power that can be safely carried in a transmission line of a given length under standard ambient conditions.
load	The aggregate demand for electricity consumed by devices connected to the electric grid; sometimes also used to include the customers who own and operate those devices.
load duration curve	The distribution function for electrical demand in a particular region, typically formed using hourly load data for a year (8,760 points) ordered from highest to lowest, each showing the electrical power required by the load in a different hour of the year.
load factor	The ratio between average and peak power.
load management/ load control	Demand response programs that offer customers incentives to reduce their consumption in response to an instruction or signal from the system operator.
locational marginal price	For any economic dispatch, the marginal cost of meeting a small increment of load at a particular location; the spot price of electricity at that location.
loop flow	An undesirable flow of power over a secondary transmission path, potentially causing congestion and unfavorable economic operation.

losses	The difference between generated power and power delivered to the load, typically caused by resistance in transmission lines and transformers and converted to waste heat.
low-voltage ride through	The ability to maintain system operations and integrity despite a low-voltage event, principally due to a short-circuit fault.
microgrid	A part of an electric power system consisting of distributed generators, loads, and specialized controls that is capable of operating either in parallel with a utility system or as a stand-alone system.
N-1 contingency analysis	Evaluation of the transmission line and transformer power flows and bus voltages in case of the loss of a single component, such as a particular generator.
phase angle	The time, expressed as an angle, by which a voltage and current waveform, or two voltage or two current waveforms, are shifted relative to each other.
phasor	A mathematical concept used to represent a sinusoidal wave as a magnitude and phase angle, where frequency is implicit. Voltage and current waves on the power system are sometimes expressed as voltage and current phasors since their frequency is constant (60 hertz in North America).
phasor measurement unit (PMU)	A device used to measure current, voltage, and frequency every 1/30th of a second or faster in synchronicity with other such measurements across a wide area based on a Global Positioning System time signal.
plug-in hybrid electric vehicle (PHEV)	A vehicle with an internal combustion engine as well as batteries that can be charged using an external power source.
power	The rate at which energy is flowing.
power electronics	Electronic circuits, employing switching electronic semiconductor devices, whose function is to control electrical energy and convert it from one form to another, e.g., from alternating current to direct current, or alternating current at one frequency to alternating current at another frequency.
power factor	The ratio of real power to apparent power. Reflects the degree to which a given amount of current is producing useful work.
power quality	The extent to which the voltage waveform at a load conforms to the ideal sinusoidal shape and nominal value. Poor power quality is generally the result of loads that draw current that is not sinusoidal (a particular problem with electronically controlled loads) or weak distribution networks producing frequent outages or voltage sags.
price responsive demand	Load that responds to prices that vary with system supply-and-demand conditions.
public utility commission	A state agency typically responsible for regulating retail electric rates and other utility prices.
reactance	The property of a conducting device that introduces a phase shift between voltage and current and introduces an impediment to the flow of alternating current.
reactive power	Power that exists in ac power systems when reactance is present. Reactive power charges and discharges the energy stored in reactive elements. It does no time-average work, but its presence still contributes to electrical losses and voltage drops.
real-time pricing	See dynamic pricing.
regional transmission organization (RTO)	An independent system operator (ISO) that the Federal Energy Regulatory Commission has certified to have satisfied a specified set of requirements and that has slightly greater responsibilities for system reliability than ISOs that have not been so certified.

regulation	In electric power systems, a control scheme that attempts to maintain some quantity at a nominal value or within a nominal range. This term is often applied to the concept of maintaining voltage and frequency within certain bounds. Also refers to the activity of a government agency charged with controlling the behavior of a public utility or other entity.
remote terminal unit (RTU)	An electronic device used for interfacing between the supervisory control and data acquisition system and the physical world.
renewable portfolio standard	A state-level requirement that a minimum fraction of in-state electricity consumption correspond to generation from specified renewable technologies, such as wind, solar, or geothermal.
resistance	The property of a conducting device to resist the flow of current through it.
rights-of-way	Geographical areas occupied by power transmission lines.
static volt-ampere-reactive compensator (SVC)	A power electronics device belonging to the family of devices known as "flexible alternating current transmission systems" used for voltage control by injecting and withdrawing reactive power.
superconductor	A material with resistance that goes to zero when cooled to temperatures in the range of 21 Kelvin or below.
supervisory control and data acquisition (SCADA)	Specialized computer systems that monitor and control industrial processes, including the operation of components of the electric grid, by gathering and analyzing sensor data in near real time.
synchronized phasor measurement (synchrophasor)	The measurement produced by phasor measurement units; a voltage or current phasor that has been synchronized with other such measurements using a common time signal from the Global Positioning System.
system average interruption duration index (SAIDI)	Reliability indicator that measures the average outage duration for each customer served.
system integrity protection scheme (SIPS)	A protection scheme that takes action based on a combination of local and remote measurements to counteract propagation of a major system disturbance.
time-of-use rates	Rate schedules that establish fixed time periods based on average system load characteristics, across which prices vary. Typical time-of-use tariffs divide weekdays into two or three time periods (peak, off-peak, and perhaps an intermediate block) and assign weekend hours to an off-peak block. Prices increase from off-peak through peak hours, and the entire tariff schedule may change across seasons.
transformer	A device used to connect two alternating current circuits operating at different voltages.
transmission network	The part of the power system that carries electric power over moderate to long distance, usually at high voltage.
transmission overlay	A network of transmission lines to be superimposed on the existing transmission network. Usually refers to lines that are longer and have higher voltage and capacity than existing lines.
unit commitment	The process of scheduling a generator (unit) to provide energy during a specific time period.
variable energy resource (VER)	A generator for which output varies over time and is imperfectly predictable, e.g., wind- and solar-powered generators.
vertical integration	In the electric power sector, a situation in which an entity that distributes electricity to retail customers also owns generation and transmission facilities that are connected to its distribution system.

volt (V)	Unit of electric potential and electromotive force, equal to the difference of electric potential between two points on a conducting wire carrying a constant current of one ampere when the power dissipated between the points is one watt; roughly analogous to water pressure in a pipe.
volt ampere (VA)	A measure of apparent power that defines the capacity of equipment, such as transformers or generators, that is limited in voltage and current. It combines both real (time average) and reactive power components.
volt-ampere reactive (VAR)	The unit used to measure reactive power, which is present in an ac system when current and voltage are out of phase.
voltage	The value of electromotive force or potential difference, expressed in units of volts.
voltage source convertor (VSC)	A power electronic device for converting a direct current voltage to an alternating current voltage.
watt (W)	The standard unit of electric power, the rate at which work is done when one ampere of current flows through an electrical potential difference of one volt.
watt-hour	A unit of electrical energy equal to 3,600 joules.
Western Interconnection	One of the two major synchronized alternating current power grids in North America. It stretches from Western Canada south to Baja California in Mexico, reaching eastward to just over the Rockies into the Great Plains.
wide-area measurement systems (WAMS)	A network of devices, usually consisting of phasor measurement units, that measures quantities of interest on the transmission network across a large geographic area in real time.

Acronyms and Abbreviations

ac	alternating current
ACE	area control error
AGC	automatic generation control
AMI	advanced metering infrastructure
AMR	automatic meter reading
BEV	battery electric vehicle
CAES	compressed air energy storage
CEUD	consumer electricity usage data
CIP	Critical Infrastructure Protection
CIS	customer information system
CREZ	Competitive Renewable Energy Zone (Texas)
CVR	conservation voltage reduction
dc	direct current
DG	distributed generation
DHS	U.S. Department of Homeland Security
DLR	dynamic line rating
DMS	distribution management system
DOE	U.S. Department of Energy
EEI	Edison Electric Institute
EHV	extra-high voltage
EIA	U.S. Energy Information Administration
EMS	energy management system
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FACTS	flexible alternating current transmission system
FCC	U.S. Federal Communications Commission
FCL	fault current limiter
FDIR	fault detection, isolation, and system restoration
FERC	U.S. Federal Energy Regulatory Commission
FIPP	Fair Information Practice Principles
FTR	financial transmission right
G	giga (10^9)
GAO	U.S. Government Accountability Office
GW	gigawatts
GWh	gigawatt hours
HAN	home-area network
HEV	hybrid electric vehicle
HTSC	high-temperature superconductor
HVDC	high-voltage direct current
Hz	hertz
ICT	information and communications technologies
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IP	internet protocol
ISO	independent system operator
k	kilo or thousand (10^3)
kV	kilovolt
kVA	kilovolt-ampere
kVAR	kilovolt-ampere reactive
kW	kilowatt
kWh	kilowatt-hour
LAN	local-area network
M	million (10^6)
MDMS	meter data management system
MVA	megavolt-ampere
MW	megawatt
MWh	megawatt-hours
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridor
NIMBY	not in my back yard
NIST	U.S. National Institute of Standards and Technology
NOAA	U.S. National Oceanic and Atmospheric Administration
NWP	numerical weather prediction
Ofgem	U.K. Office of Gas and Electricity Markets
OMS	outage management systems

P_{dc}	power output of a direct current source
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicle
PII	personally identifiable information
PMU	phasor measurement unit
PUC	public utility commission
PURPA	Public Utility Regulatory Policies Act of 1978
PV	photovoltaic
PWC	U.S. Power and Energy Engineering Workforce Collaborative
RETI	Renewable Energy Transmission Initiative (California)
rms	root-mean-square
RNM	reference network model
RPI	Retail Price Index (UK)
RTO	regional transmission organization
RTU	remote terminal unit
SAIDI	system average interruption duration index
SCADA	supervisory control and data acquisition
SGDP	Smart Grid Demonstration Projects
SGIG	Smart Grid Investment Grants
SIPS	system integrity protection scheme
SPP	Southwest Power Pool
SVC	static volt-ampere reactive compensator
TEPPC	Transmission Expansion Planning Policy Committee of the Western Electricity Coordinating Council
UTC	Utilities Telecom Council
V	volt
VA	volt-ampere
VAR	volt-ampere reactive
VER	variable energy resource
VSC	voltage source convertor
W	watt
WAMS	wide-area measurement system
WAN	wide-area network
W_{dc}	rated maximum output power of a direct current source