EAC

ELECTRICITY ADVISORY COMMITTEE

Keeping the Lights On in a New World

A Report by
The Electricity Advisory Committee
January 2009

ELECTRICITY ADVISORY COMMITTEE

ELECTRICITY ADVISORY COMMITTEE MISSION

The mission of the Electricity Advisory Committee is to provide advice to the U.S. Department of Energy's Assistant Secretary for Electricity Delivery and Energy Reliability in implementing the Energy Policy Act of 2005, executing the Energy Independence and Security Act of 2007, and modernizing the nation's electricity delivery infrastructure.

ELECTRICITY ADVISORY COMMITTEE GOALS

The goals of the Electricity Advisory Committee are to provide advice on:

- Electricity policy issues pertaining to the U.S. Department of Energy
- Recommendations concerning U.S. Department of Energy electricity programs and initiatives
- Issues related to current and future capacity of the electricity delivery system (generation, transmission and distribution, regionally and nationally)
- Coordination between the U.S. Department of Energy, state and regional officials, and the private sector on matters affecting electricity supply, demand, and reliability
- Coordination between federal, state, and utility industry authorities that are required to cope with supply disruptions or other emergencies related to electricity generation, transmission, and distribution

PURPOSE OF THIS REPORT

The purpose of the report is to address current trends with respect to construction of generation and transmission; use of demand-side resources and increased efficiency; and plans for meeting future electricity needs that will result in reliable supplies of electricity, at reasonable cost and with due regard for the environment. The report focuses on specific actions the U.S. Department of Energy can take to meet these challenges.

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January 2009

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Letter from the Chair

January 2009

On behalf of the members of the Electricity Advisory Committee, I am pleased to provide the U.S. Department of Energy with this report, ***Keeping the Lights On in a New World.*** This report recommends policies that the U.S. Department of Energy should consider enacting as it addresses the substantial challenge of helping to ensure reliable supplies of electricity in the future at reasonable cost and with due regard for the environment.

The members of the Electricity Advisory Committee represent a broad cross-section of experts, including representatives from industry, academia, and state government. I want to recognize the following EAC members who served as drafting team leaders: ***Yakout Mansour***, President and Chief Executive Officer, California ISO; ***Malcolm Woolf***, Director, Maryland Energy Administration; ***Steven Nadel***, Executive Director, American Council for an Energy-Efficient Economy; and ***Michael Heyeck***, Senior Vice President, Transmission, American Electric Power. Thanks also go to ***Kevin Kolevar***, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy; and to ***David Meyer***, Senior Policy Advisor, DOE Office of Electricity Delivery and Energy Reliability and Designated Federal Officer of the Electricity Advisory Committee.

The members of the Electricity Advisory Committee recognize the vital role that the U.S. Department of Energy can play in meeting our nation's electricity challenges. These recommendations provide actionable options for the U.S. Department of Energy to consider as it develops and deploys policies and programs to help ensure reliable, reasonably priced, and environmentally sustainable electricity service in the future.

Sincerely,

Linda G. Stuntz

Linda Stuntz, Chair

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Special thanks to ***Peggy Welsh***, Senior Consultant at Energetics Incorporated and to ***Amanda Warner***, Energy Policy Analyst at Energetics Incorporated, for their tireless support of the Electricity Advisory Committee.

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Executive Summary

The Electricity Advisory Committee (EAC or Committee) has assessed the current electric power delivery system infrastructure and concludes that it will be unable to ensure a reliable, cost-effective, secure, and environmentally sustainable supply of electricity for the next two decades.

The early warning signs of a declining electric power delivery infrastructure are visible today. Fuel transportation, particularly by rail, is congested, and any outage of a rail line can create stress on electric power supply. Coal piles at power plants have been low in the recent past. Much of the electricity supply and delivery infrastructure is nearing the end of its useful life. Without attention, natural gas demand could grow faster than the supply and capacity of the associated infrastructure to produce and deliver it. Spent nuclear fuel storage at some reactors is reaching capacity without any policy direction on long-term storage or reprocessing of spent nuclear fuel. The integration of renewable energy resources rises and falls with the ebb and flow of congressional legislation to fund the production tax credits (PTCs). The transmission infrastructure is aging and becoming more congested. Further development of the infrastructure is impeded by an archaic patchwork of cost allocation policies, fragmented permitting and siting practices, and varying needs analyses that are limited in focus and scope.

The engineering, science, and technology expertise required to meet the formidable technical challenges of keeping the lights on in the future is disappearing. The nation's university education programs in this area have generally been in decline over the past several years and show few signs of reversal. The skilled labor necessary to implement demand-side resources is also in very short supply, even as such programs ramp up to meet stronger demand.[1] These trends have put severe restrictions on the human resources pipeline. Unless these trends are reversed, recruitment outside the United States for these critical job skills will eventually be necessary.

The EAC concludes that the current infrastructure must be enhanced to meet increased electric service needs and that new policies must be implemented to protect and improve the system. A concise set of recommendations from the EAC to the U.S. Department of Energy (DOE) is included in this executive summary; more detailed recommendations are set out at the end of chapters 2–4 of this report.

Addressing the challenge of climate change is quickly becoming a national priority and has received the clear attention of the new Administration. Proposed measures to address this challenge include the targeting of emissions from all sources, expanded development of energy efficiency and renewable energy resources, and deployment of a Smart Grid. In this regard, the electricity industry is a focus of attention for emission reductions and, at the same time, a potential enabler of reducing emissions from other sources (e.g., transportation). Moreover, the current financial crisis creates not only a challenge to financing needed infrastructure but also an opportunity for the federal government to help leverage the financing of cleaner, more efficient, and reliable electric service infrastructure for the generations to come, as part of the economic stimulus initiatives. For their part, utilities and others stand ready to invest in needed infrastructure but require the stabilization of debt markets to ensure reasonable debt costs.

[1] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), http://www.nerc.com/files/LTRA2008.pdf.

There has never been a time, post World War II, with more excitement, challenges, and opportunities to enhance and reshape the United States' electricity infrastructure to meet the challenges and the needs of future years. But the action has to start now for the challenges to be overcome and the threats to become opportunities. The EAC offers this report in the spirit of helping DOE overcome these challenges and seize the opportunities.

This report includes an overview of the current bulk electricity system, followed by an exploration of the trends and drivers, barriers, and key considerations of demand-side resources, transmission adequacy, and generation adequacy. The Committee believes that the historical assessment of electricity supply adequacy, based on a planned demand/resource balance, is inadequate for ensuring future reliable and cost-effective electricity service.

The EAC's recommendations are included at the end of this executive summary, preceded by a synopsis of the findings on demand-side resources, transmission adequacy, and generation adequacy.

Demand-Side Resources

Utilities in many states have been implementing energy efficiency and demand response / load management programs (collectively called demand-side resources)—some for more than two decades. According to one source, U.S. electric utilities spent $14.7 billion on these programs from 1989–1999, an average of $1.3 billion per year.[2] Since the year 2000, investments in demand-side resources have steadily increased as states that have traditionally offered such programs have expanded their programs and other states have begun implementing new programs. In 2007 and 2008, 10 states enacted legislation or regulations setting binding energy savings goals for utilities.[3]

As spending on demand-side resources has grown, so have energy savings. Cumulative annual savings from electric energy efficiency programs were nearly 90 terawatt hours (TWh) in 2006, which is 2.4% of the total electricity sales to end-users in the same year.[4] Some states have saved 7%–8% or more of total electricity sales, making energy efficiency programs a significant utility resource.[5] Demand response / load management programs also vary, with demand response capability in 2008 ranging from about 1.7%–6.0%, depending on the region.[6] Overall, electric energy efficiency and demand response / load management programs have achieved significant levels of demand savings, which has reduced the need for generating capacity additions. For example, the Energy Information Administration (EIA) estimates that these programs collectively reduced peak demand in the United States in 2006 by 27,240 megawatts (MW), 59% of which came from energy efficiency programs and 41% of which came from demand response / load management programs.[7]

However, while much has been done to promote energy efficiency and demand response / load management programs, savings to date are only a small fraction of what is possible from this resource. For example, a review of 21 different national-, regional-, and state-level studies found that the median achievable efficiency potential (i.e., cost effective and possible to achieve as a result of policies and programs) calculated in these studies is 18% energy savings over about a 13-year period.[8] The average achievable potential per year of program implementation from these studies is about 1.5% energy savings—in line with the most aggressive programs utilities are now implementing and much greater than the approximately 0.2% per year of savings utilities are achieving on average nationwide.[9]

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[2] David S. Loughran and Jonathan Kulick, "Demand-side Management and Energy Efficiency in the United States," *The Energy Journal*, January 2004.

[3] Eldridge and others, *State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[4] Daniel York (American Council for an Energy-Efficient Economy), in discussion with Steven Nadel (American Council for an Energy-Efficient Economy), October 15, 2008. (Discussion documented in forthcoming ACEEE report on utility energy efficiency program savings.)

[5] Ibid.

[6] Federal Energy Regulatory Commission, *2008 Summer Market and Reliability Assessment* (Washington, DC: Federal Energy Regulatory Commission, May 15, 2008), http://www.ferc.gov/market-oversight/mkt-views/2008/05-15-08.pdf.

[7] Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels, *Electric Power Annual 2006* (Washington, DC: Energy Information Administration, 2007), 5, table 9.1, http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

[8] Maggie Eldridge, R. Neal Elliot, and Max Neubauer, *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned*, proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings (Washington DC: American Council for an Energy-Efficient Economy, 2008).

[9] Nationwide savings obtained from Daniel York (American Council for an Energy-Efficient Economy), in discussion with Steven Nadel (American Council for an Energy-Efficient

Similarly, recent studies have found that demand response / load management programs can reduce peak demand by 7%–22%, depending on geographic area and key assumptions.[10] In other words, current energy efficiency and demand response / load management programs are barely scratching the surface of what is achievable.

A national policy that promotes sustainable and economically viable energy efficiency and demand response / load management programs will be necessary to achieve the full potential of these resources. Policy should guide these programs to maximize cost-effective energy savings, reduce environmental impact of electric delivery infrastructure utilization (including end-use infrastructure), reduce energy use during peak periods, coordinate with Smart Grid initiatives, and enhance the overall reliability of the electric grid.

TRANSMISSION ADEQUACY

The existing interstate electric transmission network is the result of actions taken primarily by vertically integrated utilities to build generation and transmission to serve their consumers' electricity demands, to provide for the wholesale purchase and sale of electricity with neighboring utilities, and to share generating capacity reserves to minimize the amount of installed generating capacity needed to ensure adequate supplies. Today, however, the system is at an age and condition that requires significant upgrades and replacements of original infrastructure and the addition of new infrastructure to maintain an adequate bulk power delivery system for the United States. Planning of the current system did not consider broad-scale regional and interregional transfers of electricity and meeting larger national needs, such as emissions reductions and renewable energy targets. The grid must now meet the needs of wholesale markets that have evolved since the passage of the Energy Policy Act of 1992, while also reliably integrating remote sources of renewable energy generation.

Upgrading the nation's electric transmission grid is critical to ensure a reliable electricity supply, provide greater access to economically priced power, and support the growth of renewable energy generation. This generation is often remotely located and will require significant new transmission infrastructure additions to deliver these resources reliably to consumers.

Currently, state and federal agencies are responsible for siting and permitting transmission lines. Typically, each state and federal agency has its own permitting rules and processes, which are rarely consistent with each other. The uncoordinated participation of a wide spectrum of interested parties, and the nature of interstate extra-high voltage (EHV) above 345 kilovolts (kV) transmission crossing jurisdictional boundaries, complicates and impedes the effective planning, approval, and permitting processes for new EHV transmission projects.

Transmission planning and development must be done in the context of comprehensive demand and resource analysis to ensure that demand-side resources and environmentally desirable supply-side resource options are fully considered and can be accommodated by the transmission grid. Additionally, transmission planning must take into consideration the likelihood of future demand growth due to increased electrification of the transportation sector and industrial processes as the United States pursues strategies to reduce environmental impacts from these sectors. The nation needs a broad, forward-looking vision for a transmission system that will help meet long-term goals of energy security, electricity adequacy, and environmental protection.

At the same time, electricity must remain reasonably priced for consumers. Failure to keep electricity rates reasonable will have a damaging impact on the nation's economy and the quality of life for many Americans. Transmission is only a small part of the average consumer's electricity bill today, typically

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Economy), October 15, 2008. (Discussion documented in forthcoming ACEEE report on utility energy efficiency program savings.)

[10] R. Neal Elliot and others, *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demand***,** ACEEE Report E072 (Washington, DC: American Council for an Energy-Efficient Economy, 2007); Neal Elliot and others, *Texas Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs***,** ACEEE Report E073 (Washington, DC: American Council for an Energy-Efficient Economy, 2007); Eldridge and others, *Maryland Energy Efficiency: The First Fuel for a Clean Energy Future*, ACEEE Report E082 (Washington, DC: American Council for an Energy-Efficient Economy, 2008); Eldridge and others, *Energizing Virginia: Efficiency First*, ACEEE Report E085 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

less than 10%.[11] Major new transmission lines can cost more than $1 billion to construct, and planned projects must be assessed to ensure need, benefits, and minimal environmental impact. Even with the cost of significant new and upgraded transmission infrastructure, however, a properly planned and developed transmission system can facilitate lower overall costs to consumers by creating better delivery efficiencies, as well as greater market reach and reduced market power for electricity suppliers.

Generation Adequacy

The North American Electric Reliability Corporation (NERC) projects that over the next 10 years, summer peak demand will grow by 16.6%.[12] Even if these estimates prove inaccurate, and even with aggressive demand response / load management efforts, the United States will still require new generating resources. The industry will have to provide an adequate supply of electricity while improving environmental performance, integrating new resources, and retiring older generation units. Meeting this challenge will require new policies that reduce barriers to entry and support the development and interconnection of new generating capacity.

New generation projects involve considerable uncertainty and risk in today's environment. Acquiring project financing, securing long-term output contracts, dealing with political and regulatory uncertainty, coping with climate change and environmental issues, managing higher costs for fuels and new power plant construction, and navigating the siting and interconnection process make the development of new generation facilities a high-risk enterprise. If government policy is unable to reduce the financial risk and policy uncertainty that new generation projects face, generation development will be left to those few companies that have sufficient capital resources to stand alone on energy projects. It will be crucial for the new Administration to take actions that help reduce these risks and uncertainties and institute policies that encourage and support development of the new generation resources that the United States needs to power the nation's energy future.

Each of the many generation resource options offers significant opportunities for growth and development. Renewable energy, new clean coal technologies, biomass, hydroelectric power, nuclear power, combined heat and power, natural gas, electricity storage, and distributed generation are all needed to ensure a reliable and diverse supply portfolio. Policies and directions that support a diverse generation mix are vital to the U.S. energy future.

The Need for Swift Action

By any measure, 2008 was an extraordinary year. In 2009, the United States faces the near certainty of a prolonged and deep economic recession. This downturn is affecting consumers all across the country, companies in virtually every sector of the economy (including the electric power sector), and state and local governments. Current financial market conditions are placing severe restrictions on access to investment capital and will likely have a dampening effect on investment in U.S. industry for some time to come.

One result of the financial crisis may be to temporarily lower electricity demand, thus alleviating in the short term some of the pressures on electricity supply adequacy. However, this drop in demand will likely only mask the deeper and more fundamental infrastructure issues discussed in this report. Failure to address these basic infrastructure issues soon will make it more difficult to resolve the problems with the nation's electric system. The EAC therefore urges DOE and the new Administration to act swiftly on the recommendations presented in this report.

Recommendations to DOE

Demand-Side Resources

- Place priority on expanding existing DOE programs that capture energy efficiency savings (e.g., updating federal appliance/equipment standards and national model building codes) and that help develop new energy-saving technologies and practices that can be used in future decades (e.g., research and development [R&D] initiatives).

[11] Energy Information Administration, *Annual Energy Outlook 2008 with Projections to 2030* (Energy Information Administration, 2008), 131, http://www.eia.doe.gov/oiaf/aeo/pdf/0383 (2008).pdf.
[12] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), 8-9, http://www.nerc.com/files/LTRA2008.pdf.

- Develop national measurement and verification protocols/standards that will better measure the savings that are being achieved.
- Promote policies at the federal and state levels that can encourage expanded cost-effective energy efficiency and demand response / load management efforts, including expanding federal technical assistance to states and utilities, allowing demand resources to participate in independent system operator forward capacity markets, expanding regional coordination on demand-side resources, and developing energy-savings targets for utilities and/or state agencies.
- Research, develop, and support promising new energy efficiency policies and tools including energy-efficient mortgages, on-bill financing for energy-saving retrofits, energy performance ratings and disclosure for existing buildings, and use of energy-use feedback devices to help consumers better manage their use.

Transmission

- Lead comprehensive, long-term, interconnection-wide EHV transmission planning efforts by convening regional transmission organizations (RTOs), state utility commissions, regional planning councils, and other stakeholders. These efforts should be expeditious and examine the costs, benefits, and environmental impacts of transmission plans to address reliability and economics with the full range of demand- and supply-side options, including the interconnection and integration of low-carbon resources.
- Improve the process of siting transmission facilities. DOE should take a strong lead federal role for expeditious siting of transmission over federal land. Other ways to strengthen siting include: federal siting authority for EHV transmission above 345 kV; or supporting adoption of state, local, and federal “best practices,” supporting coordination of multi-agency permitting activities, and expanding National Interest Electric Transmission Corridors (NIETCs) with Federal Energy Regulatory Commission (FERC) backstop siting authority to address reliability, as well as interconnection and integration of low-carbon resources.
- Advise FERC to lead the development of broad cost allocation principles for EHV transmission. In addition, advise FERC to continue the use of formula rates for transmission recovery and encourage "pass-through" transmission rates to retail levels.
- Enhance grid operations and control by expanding research and exploring new technologies, encouraging coordination/consolidation of balancing areas where deemed economical and reliable, and ensuring the implementation of ongoing recommendations from the U.S.-Canada Power System Outage Task Force report on the 2003 blackout.
- Lead technological innovation by providing additional funding and by engaging participants in joint efforts to develop and demonstrate new technologies. Advise FERC to support continued incentives and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.
- Reduce barriers to financing and construction of transmission by supporting new transmission ownership structures and advising FERC to encourage expedited timeliness for construction of economic projects, provide opportunities for other industry participants, and encourage sound agreements for operations, maintenance, restoration, and reliability compliance where joint ownership is present.

Generation

- Reduce the risks faced by new generation developers and electricity consumers by supporting financial grants and ensuring continued funding for loan guarantees.
- Promote long-term policies, processes, and legislation that increase investor certainty and reflect the 30-year or longer lives of electricity generation plants by expanding PTCs and promoting the use of long-term investment contracts for new technologies.
- Advocate improved and longer-term certainty for air quality, water quality, and carbon emission requirements that will support the development of new generation technologies and provide needed certainty for all new generation.
- Continue supporting through grant and loan guarantee programs the development of new technologies, technology enhancements, and improved manufacturing processes for generation equipment.

- Support the development and expansion of distributed and renewable energy generation.
- Evaluate the status of generation adequacy in each region of the country in order to evaluate ways to improve performance.
- With the goal of assisting both public- and private-sector decision makers responsible for allocating generation investment, convene a review of generation technologies in a manner that integrates electric system reliability, consumer affordability, and environmental impacts.
- Advocate policies, processes, and legislation that fairly allocate interconnection and integration costs of new generation to the grid.
- Promote improved planning processes that expedite generation facility studies and interconnection agreements, and consider generation, demand response / load management, and storage solutions for reliability.

Chapter 1
Keeping the Lights On in a New World

1.1 Introduction

Reliable electricity is something that Americans expect from the bulk power supply system. It ensures that homes remain at comfortable temperatures; it enables timely, accurate responses to emergencies; it keeps industry moving and powers the millions of transactions made daily in the U.S. marketplace. An adequate, reliable, and affordable supply of electricity is critical to maintaining and improving the nation's security, standard of living, and competitive edge in a world where electricity serves as the cornerstone of a modern economy.

The U.S. electric power grid comprises thousands of individual entities that produce and deliver electricity to end-use consumers, usually without interruption. These entities are responsible for ensuring a continuous balance between electricity supply and demand, coordinating the reliable exchange of electricity between buyers and sellers over thousands of miles of high-voltage transmission lines, and maintaining the operational integrity of the current and future interconnected grid.

Currently, electricity is difficult to store so it must be generated at the instant that it is used. It flows simultaneously over many paths in the transmission networks and cannot typically be routed over selected lines, except in the case of direct-current facilities. As a result, the operation of the generators and transmission lines that make up the bulk power system must be constantly monitored and controlled to ensure that they are operating within safe limits, and that adequate, consistent, and reasonably priced electricity will remain available.

This report addresses the current trends of electricity generation and transmission, the use of demand-side resources, and future electricity needs. Through analysis of these components, the Electricity Advisory Committee (EAC or Committee), representing industry, academia, and state government, recommends policies for the U.S. Department of Energy (DOE) to consider when addressing issues related to maintaining a strong and reliable electric power service in the future.

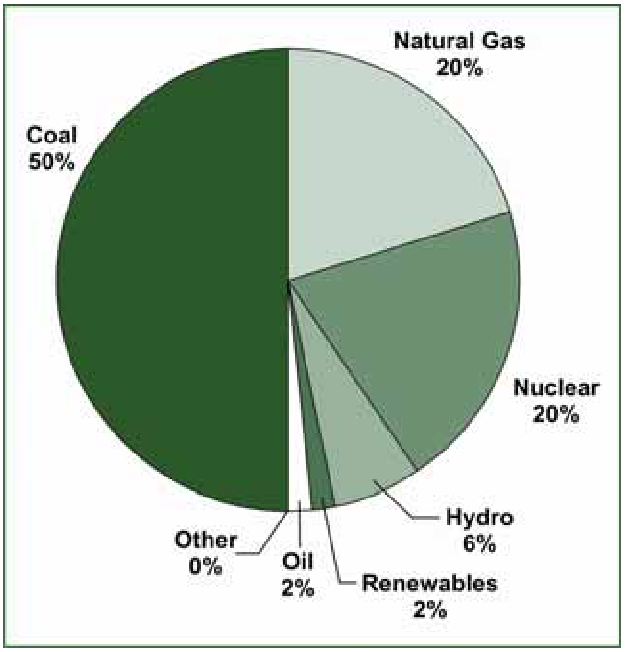
The overall purpose of this report is to provide recommendations to DOE to help ensure the smooth transition of the electric power system infrastructure in the coming years as the infrastructure addresses a "new world" of increasing demand for low-carbon resources and higher levels of reliability and complexity. This chapter provides an overview of the major elements of the bulk electricity supply and delivery system and the challenges that need to be addressed over the next two to three decades to ensure the continued reliability and efficiency of U.S. electric power service. Chapters 2–4 discuss the challenges of demand-side resources, transmission adequacy, and generation adequacy in greater detail while putting forth specific recommendations to DOE to address the electricity challenges of a new world.

1.2 U.S. Electricity Generation Resources

Currently in the United States there is a mix of generation and demand-side resource technologies available to meet demand requirements. These electricity-producing technologies vary in their availability to serve load at times of high demand, their costs, and their average capacity.

In 2007, the mix of generation resources in the United States reflected a heavy dependence on generation technologies that burn fossil fuels or use nuclear technology to produce electricity (Figure 1-1).

Figure 1-1. Electricity Resource Mix in the United States, 2007



Source: Energy Information Administration 2007.[13]

Renewable energy resources, including wind, geothermal, and solar photovoltaics, are generally higher in cost than fossil fuel–burning resources, with costs that range from as low as \$70 per megawatt hour (MWh) for the best wind power resources to as high as \$400 per MWh for solar photovoltaics. None of these costs reflect the cost of transmission needed for reliable integration of the resource into the bulk power system or the impact of subsidies (such as production tax credits) that may reduce the apparent cost of a given resource. In comparison, low-cost resources tend to include natural gas, coal, and biogas, which range from \$60–120 per MWh, depending on the cost of fuel and the location and size of the facilities. Figure 1-2 shows the levelized costs of a variety of generating technologies and fuels in the western United States. (The comparable costs for the eastern United States are assumed to be similar.) These costs reflect the expenses of owning, operating, and purchasing fuel for these resources.

The average on-peak capacity/utilization factors of resource technologies are important for determining the adequacy of total resources because they reflect each technology's dependability during peak demand periods. Average capacity factors represent the fraction of the year during which an average plant of that type is producing electricity. Figure 1-3 depicts these factors for the different resource technologies currently in use today. As the figure shows, the existing fossil fuel–burning resources (natural gas and coal) and nuclear resources have very high capacity factors, which correspond to the ability to provide peak capacity as well as a flexible, dispatchable form of energy. On the other hand, wind power, the most abundant and lowest cost renewable resource, may have an average capacity factor of 30%–40% depending on the type and location of the turbine. On-peak capacity factors of this technology, however, are typically lower. For instance, the Pacific Northwest utilizes an assumption of a 5% capacity value (capacity during peak loads), consistent with the general physical phenomenon in the Northwest of large, high-pressure systems corresponding with very hot and very cold temperatures (high load periods). The Pacific Northwest views wind power as an *energy* rather than a *capacity* resource.

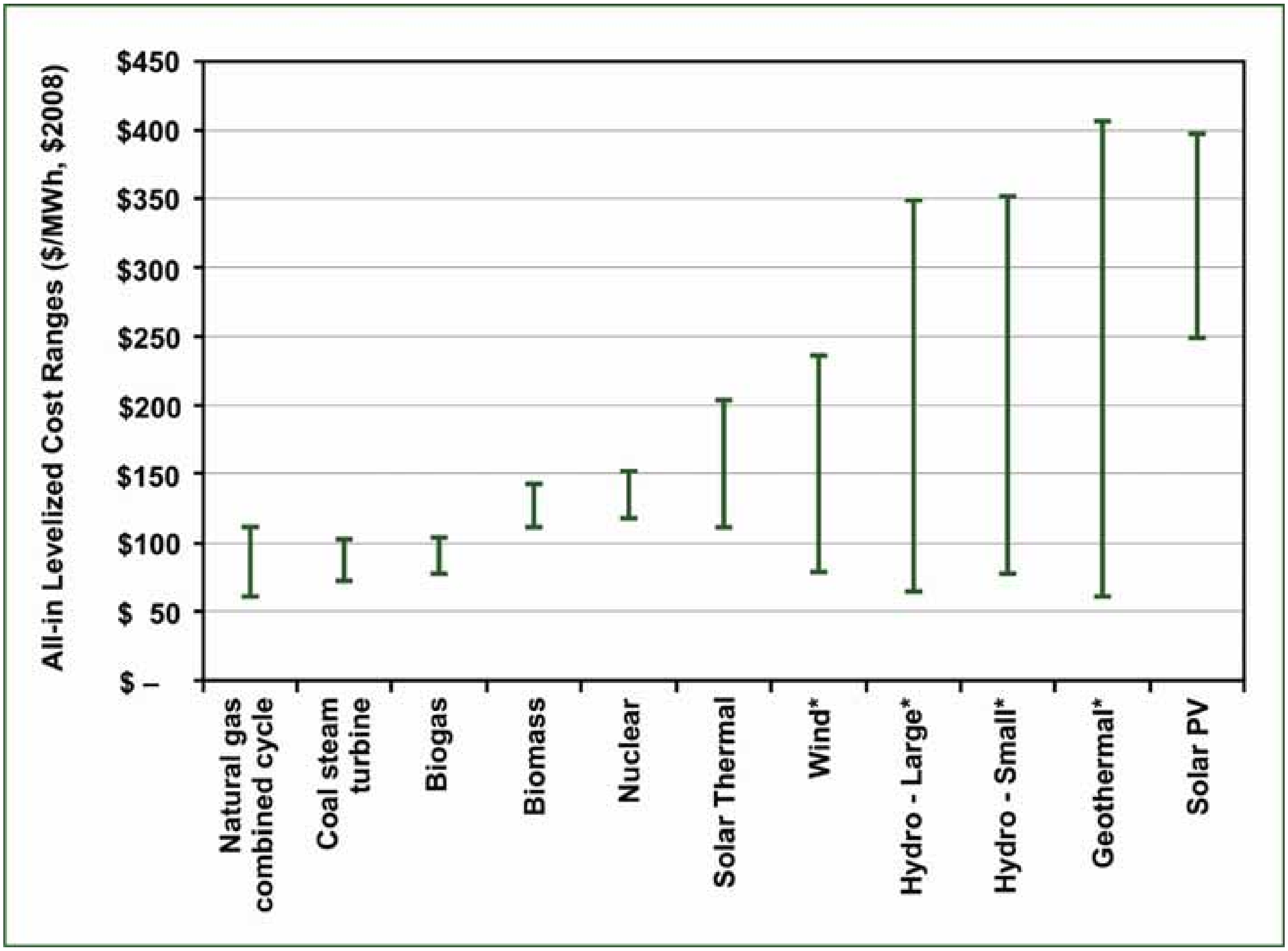
1.3 Characteristics of Resources to Meet Electricity Needs

Traditional Resources

Coal, natural gas, nuclear, and hydroelectricity resources made up 96% of electricity generation in the United States in 2007,[14] though these shares are slowly declining due to increased development of

[13] Energy Information Administration, *Annual Energy Review* (Washington, DC: Energy Information Administration, 2007), table 8.2b, http://www.eia.doe.gov/emeu/aer/elect.html. Data for 2007 are preliminary.
[14] See Figure 1-1.

Figure 1-2. Relative Cost of Conventional and Renewable Energy Resources in the Western Electricity Coordinating Council (WECC), Dollars Per Megawatt Hour (MWh), in 2008 Dollars



* The costs of resources denoted with an asterisk are highly site-specific and have wide ranges in cost depending on the project location.

Source: Energy and Environmental Economics Inc. 2008.[15]

renewable energy generation. The following section discusses the characteristics of each of these resources.

Coal

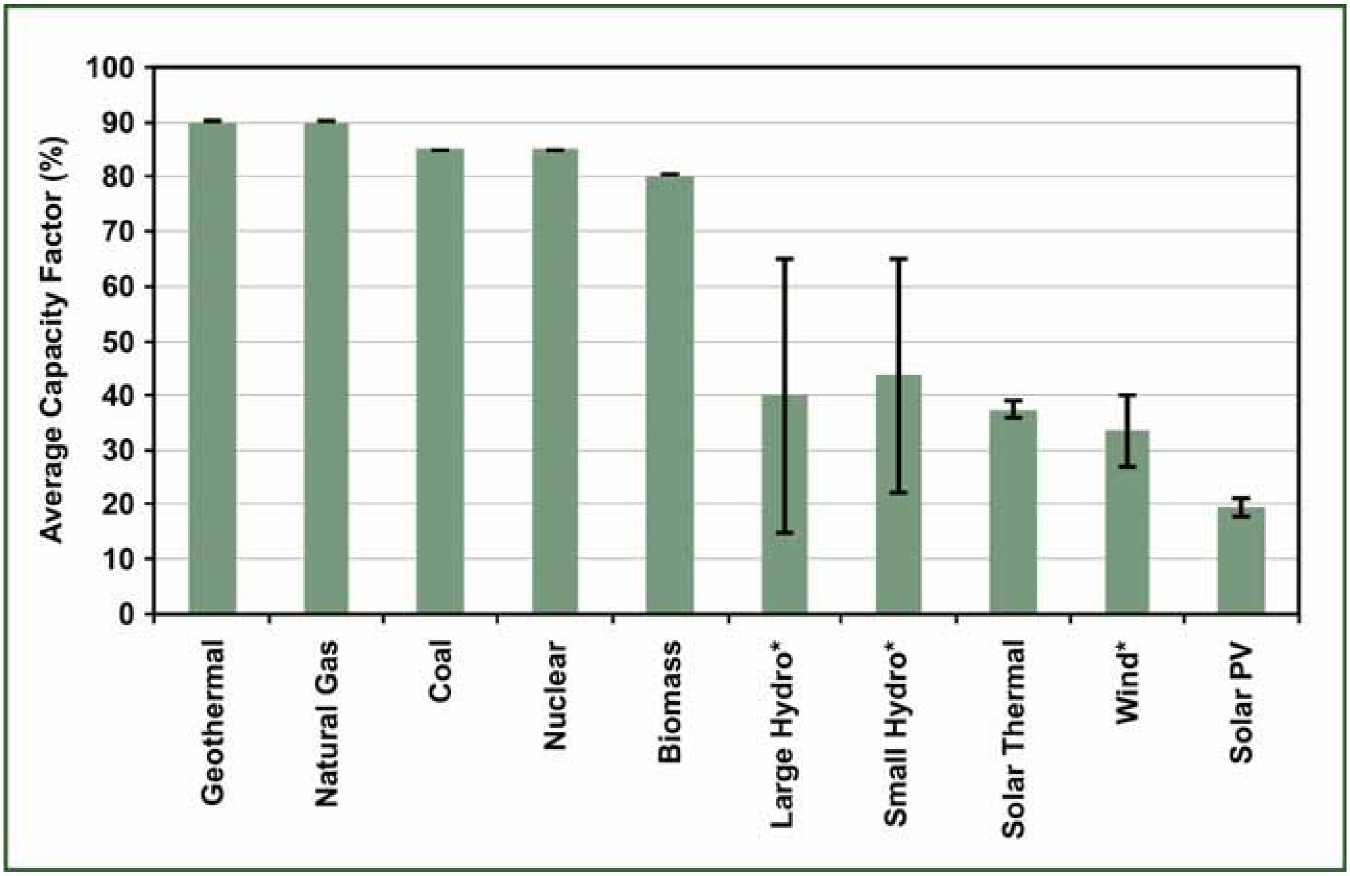
Coal has been a dominant resource in the domestic electric industry due to its relatively low cost and widespread availability, providing nearly half of the nation's electricity in 2007. U.S. coal plants are used as baseload generation due to both the historically inexpensive fuel costs and the difficulties of starting up and shutting down the units quickly, leading to a relatively high average capacity factor of 72.6% in 2006.[16]

Although it remains one of the most widely utilized electricity-producing resources in the United States, the environmental impact of coal is high on both a local and global level and at every level of the production chain. Coal mining can lead to significant landscape changes and issues with water runoff,

[15] Data developed for the California Public Utilities Commission, *Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards Into Procurement Policies*, Docket No. R.06-04-009, April 13, 2006. Documentation of the assumptions underlying the all-in levelized cost estimates are on the Energy and Environmental Economics Inc. website at: http://www.ethree.com/cpuc_ghg_model.html.

[16] Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternative Fuels, *Electric Power Annual 2006* (Washington, DC: Energy Information Administration, 2007), 5, http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

Figure 1-3. Average Capacity Factor of Conventional and Renewable Energy Resources in the Western Electricity Coordinating Council



* The capacity factors of resources denoted with an asterisk are highly site-specific and have wide ranges in performance depending on the project location.

Source: California Public Utilities Commission 2006.[17]

while coal power plants have a large footprint. Generation from coal releases significant amounts of both local pollutants (particulates, sulfur oxides [SO_x], nitrogen oxides [NO_x], and mercury) and global pollutants such as carbon dioxide (CO_2).[18]

Cooling water for coal plants can also cause environmental damage if improperly discharged into lakes or streams. Coal plants, whether they employ once-through cooling or closed-loop cooling (cooling towers), also consume water; this can be an issue where water use is a constraint. Furthermore, since coal plants are hard to site near areas that are densely populated, they often require significant transmission development, which can have environmental impacts of its own.

Natural Gas

Generation from natural gas has increased its market share in recent years, growing at a rate of about 6.8% annually over the last 10 years.[19] Natural gas-fired units are typically used during periods of

[17] Data developed for the California Public Utilities Commission, *Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards Into Procurement Policies*, Docket No. R.06.04.009, April 13, 2006. Capacity factors for hydroelectric generation and wind power resources are highly site specific. The capacity factor for solar thermal technologies depends on the technology type and vintage. The natural gas capacity factor in Figure 1-3 is based on high-efficiency combined-cycle generation. Documentation of the assumptions underlying the capacity factor assumptions are on the Energy and Environmental Economics Inc. website at: http://www.ethree.com/cpuc_ghg_model.html.

[18] Environmental Protection Agency, "Clean Energy: Coal," http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html.

[19] Environmental Protection Agency, "Clean Energy: Natural Gas," http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html.

intermediate to high demand since these units are able to quickly increase or decrease their power production.

Natural gas-fired generation has a reduced environmental impact compared to coal, releasing approximately one-half of the CO_2, one-third the NO_x, and negligible amounts of SO_x and mercury. Combined-cycle natural gas turbines also consume water and require water for cooling purposes, which can lead to environmental damage if improperly discharged into lakes or streams. Combustion turbines do not require any water for cooling, but they are far less fuel efficient than the combined-cycle units.

Nuclear

Nuclear generators make up 11% of the net summer generating capability in the United States, despite the fact that there has not been construction started on a single nuclear reactor since the River Bend reactor in 1977.[20] Nuclear generation has a high capacity factor (nearly 90%) and is used exclusively for baseload power generation due to the long time frames required to start up and shut down generation.

Though nuclear energy does not have any emissions associated with its generation, there are still significant environmental concerns surrounding further development. Foremost among these concerns is the disposal of spent nuclear fuel and irradiated plant materials that will remain radioactive for thousands of years. Nuclear power also has issues similar to other technologies in regard to using water for producing steam and cooling.[21]

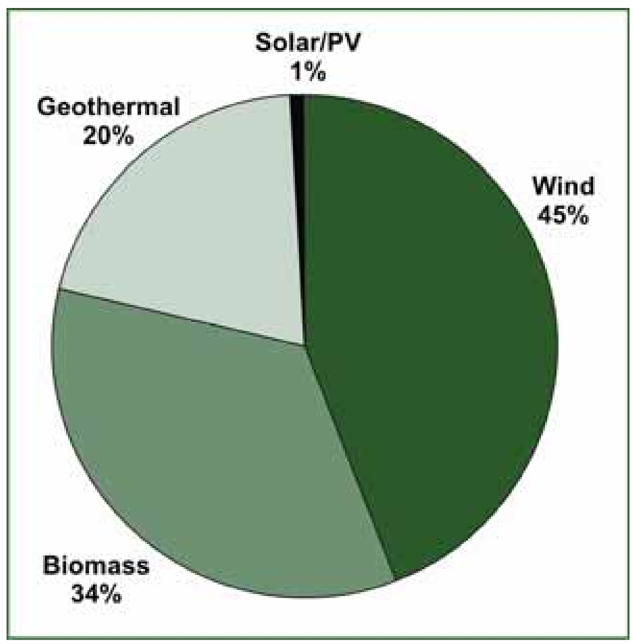
Hydro

Hydroelectric resources are currently the most significant source of renewable power in the United States, generating about 6%–8% of the electricity in 2006–2007. Hydroelectric power is generally used as baseload generation, but its availability is subject to variations in water levels and the use of water for other purposes, such as recreation and support of fish reproduction. During times of drought, hydropower often cannot produce at full capacity. When discussing the environmental impacts of hydropower, a distinction must be made between run-of-the-river hydropower and dam hydropower. Run-of-the-river installations are typically much smaller and have a significantly lower impact, while large dams flood large strips of the landscape and disturb fish migration routes, among other impacts. While hydropower does not generate any CO_2, decomposing biological materials in the inundated areas behind the dam release methane (CH_4), which has much more radiative forcing potential than CO_2. These emissions are difficult to measure and are highly site-specific, although CH_4 emissions are typically worse from dams sited in warm climates, especially tropical ecosystems.

Renewable Energy Resources

Renewable energy's share of overall generation in the United States is small but increasing. Figure 1-4 shows the share of the overall sum for each of the renewable technologies as projected for 2007.

Figure 1-4. Non-Hydro Renewable Generation by Resource



Source: Energy Information Administration 2008.[22]

[20] Energy Information Administration, "U.S. Nuclear Reactor List—Operational" (Washington DC: Energy Information Administration, November 2004), http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/operational.xls.
[21] Environmental Protection Agency, "Clean Energy: Nuclear Energy," http://www.epa.gov/cleanenergy/energy-and-you/affect/nuclear.html.

[22] Energy Information Administration, "Renewable Energy Consumption and Electricity Preliminary 2007 Statistics" (Washington DC: Energy Information Administration, May 2008), http://www.eia.doe.gov/cneaf/alternate/page/

Renewable energy, including wind power, biomass, geothermal, and solar generation, composed 2% of total electricity generation in the United States in 2007. However, this percentage is expected to increase as many states make progress toward achieving local renewable portfolio standards (RPS). Such standards typically mandate that a specific percentage of electric power supplied at retail be obtained from qualifying renewable energy technologies. As of January 2009, 28 U.S. states had adopted some form of mandatory state RPS requirements.[23]

Renewable energy's contribution to resource adequacy and on-peak capacity varies by technology type and resource location. For example, while wind and solar technologies currently operate with fairly low on-peak capacity factors (averaging 24% and 14%), geothermal and biomass provide higher on-peak capacity (with capacity factors averaging 74% and 28%).[24]

Wind Power

Wind power resources vary in quality across the United States, ranging from very high-quality Class 7 wind, often found in the midwestern high plains, to low-quality Class 1 and Class 2 winds, which are not commercially viable with existing technologies. The capacity factor of wind also varies widely, ranging from 5%–40% of rated wind power plant capacity. DOE's *20% Wind Energy by 2030* study assumed the capacity factors shown in Table 1-1 for 2005.

Table 1-1. DOE Assumed Capacity Factors

Wind Power Resource Power Class at 50 Meters	Wind Power Capacity Factor (%) in 2005
3	32
4	36
5	40
6	44
7	47

Source: U.S. Department of Energy 2008.[25]

Utilities, transmission operators, and regulators in the United States are generally less confident in the availability of wind power resources than the capacity factors used in the DOE study would suggest. The California Energy Commission; Pennsylvania, New Jersey, Maryland Interconnection LLC (PJM); PacifiCorp; Puget Sound Energy (PSE); Avista; and Rocky Mountain Area Transmission Study (RMATS) all use values close to 20% for wind power capacity factors, while other utilities apply capacity factors closer to 10% or lower.[26]

The low on-peak availability of wind power indicates that this resource is less useful for resource adequacy purposes than as an energy resource. Likewise, although wind power forecasting capabilities are improving, intermittent and unpredictable wind power remains problematic for resource planning purposes in many regions of the country.

Wind power energy generates no direct greenhouse gas (GHG) emissions, other air pollut ants, or particulate matter. However, the full environmental impact of wind power generation on migratory birds, bats, and other wildlife has yet to be determined. Specifically, some wind power projects have generated concern that the rotating turbine blades can negatively impact migratory birds' flight paths and lead to bird and bat mortality.[27] Some wind power projects are more prone to harming wildlife than others, depending on the specific location of the project, just as some wind turbine technologies are

renew_energy_consump/reec_080514.pdf. Data for 2007 are preliminary.

[23] See the Database of State Incentives for Renewables and Efficiency (DSIRE), available at http://www.dsireusa.org.

[24] Implied on-peak capacity factors of renewable energy technology types are calculated based on data from Energy Information Administration, "Renewable Energy Consumption and Electricity Preliminary 2007 Statistics" (Washington DC: Energy Information Administration, May 2008), http://www.eia.doe.gov/cneaf/alternate/page/renew_energy_consump/reec_080514.pdf. Data for 2007 are preliminary.

[25] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* (Washington, DC: U.S. Department of Energy, 2008), http://www.20percentwind.org/20percent_wind_energy_report_revOct08.pdf.

[26] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* (Washington, DC: U.S. Department of Energy, 2008), http://www.20percentwind.org/20percent_wind_energy_report_revOct08.pdf.

[27] Altamont Pass Avian Monitoring Team, *Altamont Pass Wind Power Resource Area Bird Mortality Study*, prepared for Alameda County Community Development Agency (Portland, OR: Altamont Pass Avian Monitoring Team, July 2008), http://www.altamontsrc.org/alt_doc/m21_2008_altamont_bird_fatality_report.pdf.

more wildlife-friendly than others.[28] Large wind power development projects face other siting issues, including concerns about the terrestrial footprint or the impact on marine life in the case of offshore wind power projects, or potential interference with some radar installations and low-level military flight training routes.[29]

Solar Photovoltaic

There are two principal forms of solar photovoltaic (PV) installations: distributed PV and utility-scale PV. Distributed PV installations are typically small in size (only a few kilowatts [kW] in capacity) and are often “behind-the-meter,” meaning that from the utility perspective they are considered a demand reduction rather than a source of supply. Distributed PV makes up the vast majority of current PV installations. Utility-scale PV is typically larger in size (closer to 1 megawatt [MW] or larger in capacity), and is ground-mounted as opposed to being located on rooftops as typically is the case with distributed PV. The United States is beginning to develop utility-scale PV, though it is still in its infancy as a large-scale generation technology. Both distributed and utility-scale solar PV installations have a capacity factor in the range of 18%–21% because they are limited to only producing power when the sun is shining.

Solar PV produces no direct air pollution or GHG emissions and requires no water for cooling unlike geothermal, solar thermal, and biomass resources. The principal environmental concern with solar PV is that the chemicals required to produce the panels and often utilized in the panels themselves can be harmful pollutants such as cadmium telluride, which is used extensively to make some of the lower cost thin-film resources. This effect can be mitigated somewhat by the proper care and disposal of the units. Utility-scale solar PV raises additional concerns about the impacts on wildlife and local ecosystems when large land areas are required for ground-mounted solar PV facilities.

Concentrating Solar Thermal

As a solar-powered technology, concentrating solar thermal energy is only available during daylight hours, with availability varying by region and weather patterns. Unlike solar PV, most solar thermal technologies require direct solar rays known as direct normal insolation (DNI), which means that performance declines significantly under cloudy conditions. Some solar thermal technologies can store thermal energy for a few hours by transferring it to silicon oil or molten salt. Thermal storage capabilities may be available for up to six hours, increasing the capacity value of solar thermal as an energy source from 10% up to 40%.[30]

While solar thermal energy produces no direct GHG emissions or air pollutants, solar thermal projects require relatively large land areas to generate energy at the utility scale. The terrestrial footprint of solar thermal technologies can interfere with natural patterns of sunlight, rainfall, drainage, or other existing land uses, such as grazing. Water availability is another concern, as the optimum solar resources rely on water for cooling, yet are typically located in the Desert Southwest.

Geothermal

Geothermal power uses the heat contained in subterranean geologic strata to generate electricity. The heat driving the generation process typically comes from subterranean hot water or brine trapped in porous rock that is brought to the surface in a well. Geothermal is a baseload resource, is available during all hours of the day, is independent of weather conditions, and has no associated fuel costs. The Energy Information Administration’s (EIA) *Annual Energy Outlook 2008* estimates geothermal’s capacity factor to be 90%.

The primary environmental impact of generation from geothermal resources is water use. Water is typically used as the cooling agent in geothermal energy production, though at a rate of approximately 5 gallons per MWh, compared to nearly 360 gallons per MWh consumed by natural gas-fired generators.[31] No fossil fuels are burned in the

[28] U.S Government Accountability Office, *Wind Power: Impacts on Wildlife and Government Responsibilities for Regulating Development and Protecting Wildlife*, GAO-05-906 (Washington DC: GAO, 2005), http://www.gao.gov/new.items/d05906.pdf.

[29] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy’s Contribution to U.S. Electricity Supply* (Washington, DC: U.S. Department of Energy, 2008), http://www.20percentwind.org/20percent_wind _energy_ report_revOct08.pdf.

[30] L. Stoddard, J. Abiecunas, and R. O'Connell, *Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California*, NREL/SR-550-39291 (Kansas: Black & Veatch, April 2006), http://www.nrel.gov/csp/pdfs/39291.pdf.

[31] Alyssa Kagel, Diana Bates, and Karl Gawell, *A Guide to Geothermal Energy and the Environment* (Washington, DC:

process, although geothermal generation can result in a small amount of fugitive GHG emissions.

Biomass

Biomass encompasses a number of different technologies and fuel sources, including wood, forestry waste, crop waste, dedicated biomass crops (e.g., switchgrass), municipal solid waste (MSW), landfill gas (LFG), and gases produced from dairy wastes and municipal wastewater treatment. More specifically, biomass refers to technologies that burn biomass fuels and use the heat to operate a steam turbine. Biogas refers to technologies that burn gaseous biomass fuels in a combustion turbine or reciprocating engine.

Biomass combustion turbines can operate at capacity factors competitive with traditional turbines, estimated at 80%–85%. The limiting constraint on biomass is feedstock availability, which has traditionally been limited by the price of coal as a fuel substitute. In 2001, EIA estimated that with coal prices at $1.23 per million British thermal units (Btu), economically available biomass feedstock could generate up to about three gigawatts (GW) of capacity in the United States. Higher demand for renewable energy resources and/or higher coal prices could generate more economically attractive biomass feedstock.

Despite the fact that biomass combustion produces GHG emissions, there are no net CO_2 emissions from biomass generation when the entire biomass fuel cycle (carbon cycle) is taken into account. Thus, biomass is generally considered to be a zero-carbon fuel. Biomass combustion produces particulate matter as well as other air pollutants such as SO_x and NO_x; however, it is generally less polluting when compared to coal-fired generation.[32]

Demand-Side Resources

While the above technologies all constitute sources of electricity generation that can be developed to serve load, demand-side resources can serve adequacy needs by reducing load, thus reducing the need for new generation. "Demand-side resources" typically refers to one of two methods of reducing load: energy efficiency or demand response / load management.

Energy Efficiency

Energy efficiency is the concept of designing and deploying improved technologies that can perform the same function as existing electricity end-uses while reducing electricity use. Relatively efficient alternatives exist for a widespread array of products and applications, including refrigerators; lighting; and heating, ventilation, and air conditioning (HVAC) systems. However, products do not have to use electricity in order to be able to promote energy efficiency. Building materials and designs can reduce electricity use as well.

Market barriers to energy efficiency reduce its penetration rates, despite the fact that many energy efficiency measures are cost effective (i.e., produce net benefits relative to cost) over their lifetimes. One market barrier is the typically higher up-front cost of energy-efficient appliances and measures, which may discourage consumers from purchasing them. This issue is typically addressed by an energy efficiency program that provides incentives (e.g., rebates or free appliance replacement) to consumers who purchase or use energy-efficient products, or through local, state, or national regulation that requires the use of energy-efficient products. Many of these codes and statutes apply to buildings, setting a baseline for the appliances and materials they use to promote a minimum level of efficiency.

The cost of energy efficiency varies widely. In some cases, the incremental cost of installing or purchasing a more efficient product is less than the cost of the energy that it would take to run the less efficient product. For example, a 2004 study by Resources for the Future found that the development of efficiency standards for appliances provided energy savings at a cost of approximately 3.8¢ per kilowatt hour (kWh),[33] compared to the average nationwide electricity price of 7.6¢ per kWh at that time.[34]

Geothermal Energy Association, 2007), http://www.geo-energy.org/publications/reports/Environmental%20Guide.pdf.

[32] Zia Haq, Energy Information Administration, "Biomass for Electricity Generation," http://www.eia.doe.gov/oiaf/analysispaper/biomass/pdf/biomass.pdf.

[33] Kenneth Gillingham, Richard G. Newell, and Karen Palmer, *Retrospective Examination of Demand-Side Energy Efficiency Policies* (Washington, DC: Resources for the Future, 2004), http://www.rff.org/Documents/RFF-DP-04-19rev.pdf.

[34] Energy Information Administration, *Electric Power Annual* (Washington, DC: Energy Information Administration, 2008) table 9.2, http://www.eia.doe.gov/cneaf/electricity/epa/epat9p2.html.

While energy efficiency is typically promoted as a way to reduce energy usage, it can also serve to substantially reduce peak electricity demand. Many of the appliances commonly targeted by energy efficiency programs are the same appliances that contribute to a utility's demand. Air conditioning units are a prime example of this, as peak demand is usually correlated with the hottest days of the summer when air conditioners are running at full capacity. EIA estimates that energy efficiency programs reduced peak demand by 15,959 MW in 2006, or the equivalent of 32 typical power plants (500 MW generators). Throughout 2006, energy efficiency was estimated to reduce total energy usage by an estimated 62,591 gigawatt hours (GWh). However, it is difficult to estimate the impact that energy efficiency programs will have on peak loads and energy usage in the future, as it is highly dependent on the technologies deployed and the level of deployment.

The environmental benefits of energy efficiency are vast, as it reduces the need for more generation. This, in turn, eliminates the environmental impacts of the displaced generation. As different geographic areas around the United States rely on highly varied generation portfolios, efficiency can have a greater or lesser environmental benefit, depending on where it is deployed.

Demand Response / Load Management

Demand response, also referred to as load management and demand-side management (DSM), consists of encouraging consumers to reduce their electricity consumption during times of especially high demand. This encouragement is typically done by enrolling consumers in utility-sponsored demand response / load management programs. Historically, the peak reduction caused by demand response / load management has been hard to predict because it depends on individual decisions made at the consumer level. However, recent inclusion of demand response / load management resources in capacity markets, such as Independent System Operator-New England's (ISO-NE) Forward Capacity Market and PJM Interconnection's Reliability Pricing Model, is resulting in an increased reliance on long-term contracted demand response / load management that can be compared more easily with generation resources.

The cost of demand response / load management, like energy efficiency, is highly variable to the point where each consumer can receive a different payment to reduce his or her load. However, the recent forward capacity auctions mentioned above have provided some information as to the amount of demand response / load management consumers are willing to provide at the clearing price of the auction. In PJM's auction for the 2011–2012 delivery year, 1,365 MW of demand response / load management cleared at a price of $110/MW per day, or the equivalent of about $4.58/MWh.[35] In ISO-NE's recent auction for the same time period, 2,554 MW of demand response / load management resources cleared when the auction reached its price floor of $4.50/kW per month, or roughly $6.25/MWh per month (for a 30-day month).[36]

While demand response / load management has the environmental benefit of reducing the need to build additional power plants to serve the system peak, it does not necessarily reduce the amount of electricity generated in a given year. Demand response / load management often serves to simply shift electricity consumption to a different time period. The EIA estimates that load management reduced the peak load in 2006 by 11,281 MW but only reduced energy usage that year by 865 GWh. This represents a peak load savings of 71% of the size of energy efficiency's estimated peak savings but only 1.4% of the size of energy efficiency's estimated energy savings.[37] With the introduction of sizeable intermittent renewable energy resources, the evolution of smarter devices at the demand side, and the increasing attention to the Smart Grid concept, demand response / load management could play a major role in reshaping the historical demand curve every day of the year, rather than only on peak days, in a manner that reduces reliance on traditional generation facilities.

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[35] PJM, "2011/2012 Base Residual Auction Results," May 2008, www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction.../20080515-2011-2012-bra-results-spreadsheet.ashx.

[36] Independent System Operator-New England, "ISO New England Inc., Docket No. ER08-___-000 Forward Capacity Auction Results Filing" (Washington, DC: Schiff Hardin, March 2008), http://www.iso-ne.com/regulatory/ferc/filings/2008/mar/er08-633-000_03-03-08_fca_results_filing.pdf.

[37] Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, *Electric Power Annual* (Washington, DC: Energy Information Administration, 2008), table 9.2, http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

Combined Heat and Power

Combined heat and power (CHP) systems are located at consumer facilities (primarily industrial and very large commercial facilities) and generate both power and steam. The steam is used on site (or nearby) for process heat or space conditioning, and the power may be used on site or sold to the grid. These plants can have very high efficiency (45%–80%) because much of the heat is used and not wasted. According to EIA, in 2006, CHP systems generated about 322 terawatt hours (TWh) of electricity, accounting for 7.9% of net generation that year.[38] Several studies have estimated that the amount of power from CHP could be increased by more than 50%.[39] On the other hand, realizing this potential will require the overcoming of a variety of barriers, ranging from host-site reluctance to get into the power business, fluctuations in gas and electricity prices over time, and problems with environmental regulations and interconnection requirements in some service areas and jurisdictions.

1.4 TRANSMISSION RESOURCES

The U.S. electric grid infrastructure consists of about 3,000 consumer-serving entities and 500 transmission owners. This makes the U.S. grid system unique compared to the rest of the world. It also presents a distinct set of challenges in transmission planning, operating, siting, investment, regulatory oversight, and access. The development and deployment of a national strategy on transmission that meets the needs of all market participants and consumers is extremely complex; yet, it is desperately needed.

The high-voltage transmission network in the United States comprises nearly 164,000 circuit miles of transmission lines at voltages 230 kilovolts (kV) and above. The total number of transmission miles is projected to increase by 9.5% (15,700 circuit miles) over the next 10 years. This figure represents 1,700 more circuit miles projected to be added over the coming 10-year period, when compared to projections one year ago.[40] Other reinforcements to the bulk power system, like new transformers and reactive power sources, are also planned and will further strengthen the system.

More transmission resources and investments will be needed, however, to maintain reliability and integrate new resources as aging infrastructure is replaced and changes are needed to the transmission system topology. New generation supply is projected to outpace transmission development by nearly two times. Further, many new supply resources are likely to be located remote from demand centers (e.g., wind power generation) and constrained to those areas. The amount of transmission required to integrate these resources is significant.

From 1974 to 1983, annual investment in transmission infrastructure averaged about $5 billion in 2005 dollars. In the next 10-year period, average annual investment fell to $3.7 billion and by 1993–1994 hit a low of $2.5 billion. Since that time, annual investments have begun to climb, reaching $5.8 billion annually in 2005, with projections to exceed $8 billion in 2009. This remains a very small component of an industry with $800 billion of capital that is projecting a need for $200 billion in the next three years.

Lagging investment in transmission resources has been an ongoing concern for a number of years. More investment is required as each peak season puts more and more strain on the transmission system, especially in constrained areas such as California and the Desert Southwest.

The process to site new transmission continues to be difficult, time-consuming, and expensive due to local opposition, environmental concerns, insufficient information provided by project proponents, land-agency staffing constraints, and the need for state and federal planning and permitting coordination, especially for proposed lines that would cross state borders. Such factors delay and, in some cases, stop projects from being built. As a result, transmission permitting, siting, and construction frequently take significantly longer (i.e., 7–10 years) than the permitting, siting, and construction of generation.

Transmission lines are the critical link between the point of electricity generation and consumers. As

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38 Ibid., table 1.1.

39 Anna Shipley and others, *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future* (Oak Ridge, Tennessee: Oak Ridge National Laboratory, December 1, 2008), http://www1.eere.energy.gov/industry/distributedenergy/pdfs/chp_report_12-08.pdf.

40 North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), http://www.nerc.com/files/LTRA2008.pdf.

demand grows and generation is built in areas remote from the demand, more capacity on the transmission system is needed to meet demand. Underinvestment in transmission puts additional strain on existing resources, raising the risk of system disturbances, lengthening restoration time when outages do occur, and limiting access to remote generation.

1.5 CONTROL CENTERS

Control centers are the nerve center of any large-scale electric power system. There are several levels of control centers, each defined by the magnitude and number of loads served, generation coordinated, and transmission operated. An independent system operator (ISO) or regional transmission organization (RTO) uses its control center to manage and operate the assets under its purview in order to accomplish its various tasks. The primary function of a control center is as an interface between the power system and the system operators responsible for operating it.

Data acquisition allows system operators to monitor the condition of the system and implement supervisory (manual) controls, such as opening and closing circuit breakers to engage or disengage transmission lines in the network or switching in and out shunt capacitors or reactors to control voltage levels throughout the network. A Supervisory Control and Data Acquisition (SCADA) system uses a communication system to gather system-wide data sequentially at a rate in range of 2–10 seconds (s) per measurement. The fastest scan rates (2–4 s) are used to collect the data needed for Automatic Generation Control (AGC), which controls tie line power flows and generator outputs. This system is the main wide-area control in use today. It can effectively act on a slow time scale and therefore does not require high bandwidth communication. The energy management system (EMS) software in most control centers provides a number of computational tools to assist the operators in reaching their decisions, but very little, if any, of this is implemented as a closed-loop or automatic control.

Some control centers also perform the important task of scheduling power transactions that are managed by the system operators. A principal role for such a control center is to facilitate markets (i.e., to support as many transactions as the various market players require to conduct their businesses). This role is discharged under the constraint of maintaining the reliability and security of the interconnected system. The system operator also has the obligation to provide transmission service to all consumers through open, nondiscriminatory access to available transmission capacity and to have an adequate supply to maintain reliable and efficient electricity. The system operator has the responsibility to acquire and supply all necessary services, such as ancillary services, to fulfill this obligation. Finally, as defined by the Federal Regulatory Energy Commission (FERC), the ISO/RTO is independent of all market participants, having no ownership/financial interests in any of these entities and vice versa.

In addition to operating under normal conditions, control centers are designed to operate when there are emergencies that cause system stress and during restoration when there are widespread outages of equipment that have left all or portions of load unserved. The loss of a control center poses a serious threat to the operations of an electricity system. For this reason, emergency planning dictates the existence of a backup control center that can assume the appropriate functions of the primary center at any time it is needed.

The effectiveness of a control center’s capability to enable the system operators to do their job depends on the tools and technology available. The complexity of the planning and operation tasks performed under the severe reliability and security constraints imposed during an emergency is an enormous challenge both technically and institutionally.

1.6 HUMAN RESOURCES

The United States has become a technological society fully dependent on certain critical infrastructures like the bulk power system. This system has been cited as the greatest engineering achievement of the twentieth century by the National Academy of Engineering. The engineers who created it were educated mostly at universities in the United States. The engineering faculties and graduate students at those universities have conducted much of the research needed to support the continuing evolution of the system. This group of industry and academic experts is as important an asset to the safe, reliable, and economical operation of the bulk power system as any generator, transmission line, or control center. It is also an asset that is at risk.

More than 50%, or about 200,000, current utility workers are eligible for retirement by the year 2010. The electric power industry's engineering workforce is aging, and engineering work is increasingly being outsourced. According to the DOE report prepared in response to Section 1101 of the U.S. Energy Policy Act of 2005 on current trends in the workforce,[41] "in 2004, there were 10,280 electrical engineers working in the electric power generation, transmission, and distribution industry. By 2014, the Bureau of Labor Statistics projects demand will grow to 11,113."

In 2007, the North American Electric Reliability Corporation (NERC), the organization responsible for setting the rules and monitoring the reliability of the bulk electric system, listed the manpower deficit as one of three major threats to maintaining the future reliability of the bulk power system.[42] NERC updated the DOE statistics of 2005 by noting that 40% of senior electrical engineers and shift supervisors will be eligible for retirement in 2009, and that there will be an increase of 25% in demand for industry workers by 2015.

At the same time, the undergraduate student enrollment in power systems engineering programs in the United States has been diminishing and is not improving, primarily because the number of power system programs at universities is declining. Graduate student enrollment has been steadier because of the large percentage of foreign students in the Master of Science (MS) and doctorate (PhD) programs. The power engineering faculty in the United States are growing older, with the average age of the professoriate creeping upward and the number of years remaining in their professional lives rapidly decreasing. The number of faculty retirements is outpacing the number of faculty additions, and the trend is not showing signs of reversal.

[41] U.S. Department of Energy, *Workforce Trends in the Electric Industry: A Report to the United States Congress Pursuant to Section 1101 of the Energy Policy Act of 2005* (Washington, DC: Department of Energy, August 2006), http://www.oe.energy.gov/DocumentsandMedia/Workforce_Trends_Report_090706_FINAL.pdf.

[42] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), http://www.nerc.com/files/LTRA2008.pdf.

1.7 Electric Service Institutions

The policy challenges facing DOE and the nation to ensure a reliable and efficient electricity service are further complicated by the fragmented structure of the electric industry. The industry includes a large and complex array of participants with varying business models and objectives and is governed by a complex scheme of state, federal, and self-regulation. These complexities must be understood and taken into consideration as DOE works to meet its electricity policy goals.

Types of Electric Utilities

There are three types of electric utilities providing electric service to the nation's residential, commercial, and industrial consumers:

- **Investor-owned utilities (IOUs)**—Approximately 220 IOUs provide service to 96 million consumers (approximately 68.6% of all consumers).[43] These electric utilities are owned by shareholders and operate using a for-profit business model. IOUs' retail electric services are regulated at the state level by state public utility commissions (PUCs), while their wholesale sales and interstate transmission services are regulated by FERC.[44]
- **Rural electric cooperatives (co-ops)**—Approximately 930 rural electric cooperatives (co-ops) provide service to 17.5 million consumers (approximately 12.4% of all consumers). They are privately owned by their end-use consumers and provide service using a not-for-profit model. They are generally self-regulated by their boards of directors, although some are also subject to state, or in a few cases federal, regulation. Many co-ops borrow money from the Rural Utilities Service (RUS), a program of the U.S. Department of Agriculture (USDA), and thus must comply with RUS regulations in providing electric service.
- **Public power systems**—Approximately 2,000 public power systems provide electric service to

[43] Statistics are for 2006, the latest year for which EIA data are available, unless otherwise noted.

[44] Because the bulk of the state of Texas is served by a separate electrical interconnection—the Electric Reliability Council of Texas—which does not operate in interstate commerce, the Public Utility Commission of Texas is the sole economic regulator of electric service there.

approximately 20 million consumers (14.5% of all consumers). They are owned and operated by units of state and local governments and also operate under a not-for-profit model. They are generally self-regulated by their city councils, utility boards, or other governing bodies.

There is a broad diversity in size and sophistication among these utilities. The largest utilities serve consumers numbering in the millions, while the smallest serve only a few hundred consumers. Most of the smaller public power and co-op utilities do not participate directly in the wholesale electric market; rather, they rely on associated wholesale suppliers (generation and transmission cooperatives or joint action agencies) to obtain their wholesale power supplies and transmission service, or they contract these functions out to unaffiliated third-party suppliers. Together, IOUs, co-ops, and public power systems have 557,275 MW of nameplate generation capacity (51.8% of the industry total).

Non-Utility Power Suppliers

The restructuring of the electric power industry, which began with the passage of the Public Utilities Regulatory Policies Act of 1978, gives rise to a class of power suppliers known as "non-utility generators." These organizations may be fully independent or may be affiliates of traditional utilities. A substantial percentage of electric generation is now owned and operated by non-utility power suppliers: as of 2006, non-utility power suppliers held 445,476 MW of nameplate capacity, which is 41.4% of the industry total. They generally hold market-based rate authority granted by FERC that allows them to sell their power in wholesale markets.[45]

Federal Suppliers

In certain regions of the country, federal utilities are a major presence. The Tennessee Valley Authority (TVA) provides wholesale transmission and power supply service in a seven-state area in the Southeast to a substantial number of public power systems and co-ops, who in turn serve 4.5 million consumers. The Bonneville Power Administration (BPA) has a strong presence in the Pacific Northwest, marketing wholesale power from an extensive system of hydroelectric facilities on the Columbia River and operating a regional transmission system. Other federal utilities include the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA). All of these entities market wholesale power from federal hydroelectric projects on a cost-of-service basis, primarily to not-for-profit public power systems and co-ops. BPA, WAPA, SEPA, and SWPA are power-marketing administrations (PMAs), which are distinct and self-contained entities within DOE; TVA, however, is not operated under DOE auspices. Together, federal utilities have 72,826 MW of nameplate generation capacity (6.85% of the industry total).

1.8 MARKET STRUCTURES

Wholesale Open Access Transmission/Restructuring

Starting with the passage of the Energy Policy Act of 1992 and continuing with its Order Nos. 888 and 890, FERC has required electric utilities subject to its regulation to offer "open access" interstate transmission service on their transmission systems. These utilities have accordingly implemented Open Access Transmission Tariffs (OATTs), under which they must offer transmission service on a nondiscriminatory basis to third parties (including competing power suppliers) using common rates, terms, and conditions.

Regional Transmission Organizations

Taking the concept of open access transmission service a step further, certain regions of the country have formed RTOs as FERC strongly encouraged in its Order No. 2000. There are currently six FERC-regulated ISOs operating as RTOs: ISO-NE; the New York ISO (NYISO); the PJM Interconnection, which covers the Mid-Atlantic and some parts of the Midwest; the Midwest ISO (MISO), which covers other parts of the Midwest; the California ISO (CAISO); and the Southwest Power Pool (SPP), which covers parts of Texas, Louisiana, Arkansas, Missouri, Kansas, and Oklahoma. While not FERC regulated, the Electricity Reliability Council of Texas (ERCOT) is operating as an ISO that covers

[45] See the Federal Energy Regulatory Commission's (FERC's) standards for granting market-based rate authority, which are set out in FERC, Order no. 697, "Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities," final rule, Federal Register 72, no. 139 (July 20, 2007): 39904; FERC, Order no. 697-A, "Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities," order on rehearing and clarification, Federal Register 73, no. 89 (May 7, 2008): 25832.

most of Texas. However, other regions of the country, including the Pacific Northwest, the Desert Southwest, and the Southeast, have not formed RTOs.

RTOs direct the operation of the transmission systems in their regions that are still owned by the individual member utilities. RTOs provide nondiscriminatory regional transmission service under a single OATT with a unified regional rate structure. They also operate a variety of centralized markets for various wholesale power supply products, but they act solely as a market-maker and do not profit from transactions conducted in their markets.

Retail Access

Many IOUs, and virtually all co-ops and public power utilities, still provide electric service under a traditional vertically integrated business model, owning and operating generation, transmission, and distribution facilities and measures while selling "bundled" retail service to their end-use consumers. These utilities provide retail service under a "cost-of-service" model; thus, their rates reflect their costs of providing service plus a reasonable return (or in the case of not-for-profit co-ops and public power systems, a financial reserve). State public utility commissioners regulate the retail rates of IOUs and some electric cooperative utilities.

This traditional utility service model, however, has given way to unbundled or disaggregated business models in many regions of the country. Approximately 15 states and the District of Columbia have implemented full retail access for their IOUs, unbundling the electric distribution function from the retail power supply function.[46] Hence, these retail electric utilities now primarily provide only unbundled transmission and distribution services. Power supply service to retail consumers is handled by other suppliers at market-based rates or provided by the utility under an unbundled provider of last resort (POLR) or default supply service.

In moving to retail access, many states required their IOUs to divest their generation facilities to third parties, either affiliated or independent. The divestitures of utility generation facilities that occurred during the implementation of retail access gave the non-utility generator sector a substantial boost, greatly increasing the generation assets subject to wholesale market-based rate authority, rather than traditional retail cost-of-service regulation.

Mandatory Reliability Standards

In addition to FERC's and/or the state PUCs' economic regulation, the owners, operators, and users of the bulk power system are now subject to mandatory reliability standards intended to maintain the reliability of the bulk power transmission system. The statutory authority requiring the development and enforcement of these reliability standards was enacted as part of the Energy Policy Act of 2005, in part as a response to the August 14, 2003 blackout in the Northeast.[47]

The statutory regime features a unique pairing of private and federal entities. FERC has designated a separate not-for-profit, self-regulating industry entity called the Electric Reliability Organization (ERO) to develop and enforce the mandatory reliability standards through an industry-driven collaborative process and to assess adequacy. The designated ERO in the United States responsible for such regulation is NERC.[48] The reliability standards that NERC develops with the help of industry participants must be approved by FERC before they become enforceable in the United States. Therefore, NERC and the eight regional entities to which it delegates certain authorities and for which it enforces

[46] Kenneth Rose, *Status of Retail Competition in the U.S. Electric Supply Industry*, Testimony before the House Public Utilities Committee, The Ohio House of Representatives (February 5, 2008), http://www.ohiochamber.com/governmental/pdfs/Kenneth%20Rose-2_020508.pdf. As Dr. Rose relates in some detail, 15 states and the District of Columbia allowed retail access for all consumer classes. Twenty-six states never implemented retail access; four states repealed or did not implement their retail access regimes; three states have limited access to large consumers only; and two have suspended or delayed their retail access regimes. Even in states with retail access regimes, cooperatives and public power systems have generally continued to operate under the traditional retail service model, using cost-based rates.

[47] This new statutory authority is set out in Section 215 of the Federal Power Act, 16 U.S.C. § 824o. NERC's reliability standards can be found at http://www.nerc.com/files/Reliability_Standards_Complete_Set_25Nov08.pdf.

[48] Since the North American electric transmission system does not stop at the United States' borders, Canada and Mexico are also partners in maintaining system reliability. The Canadian provincial regulators have also recognized NERC as the North American ERO.

standards are subject to FERC oversight within the United States.

The mandatory reliability standards went into effect in June 2007. Violations of the standards can trigger very substantial monetary penalties, as well as negative public attention for the violators. Hence, the users, owners, and operators of the bulk power system subject to these standards have undertaken very substantial compliance efforts within their respective organizations.

1.9 Consumer Benefits

While electric rates are bound to rise given the challenges facing the industry, failure to keep electricity rates affordable or to maintain the quality of service that supports the backbone of the world's largest economy would damage the quality of life for Americans. In order to prevent this possibility, the electric power delivery infrastructure will need to be expanded and/or upgraded. The costs of these new facilities, which are to be paid by consumers in their electric rates, must be commensurate with the benefits they will receive. New facilities that are put into operation must address both reliability and economic needs, and they must provide consumers and utilities with access to a well-balanced portfolio of generating resources, including renewable and demand-side resources, at reasonable costs. Failure of the transmission system to deliver energy reliably and economically to end-users would have a substantial negative impact on the price and quality of service.

1.10 The Implications and Planning Challenges of Industry Structure and Institutions

The complex and unique features of the nation's electric industry make it very difficult to define a simple set of policy prescriptions to ensure that the nation's future electricity needs will be served reliably and economically with due regard for the environment. Transmission and resource planning has become increasingly complex and dependent, at least in part, on market mechanisms. Different policy choices and implementation methods are necessary in different regions, since the North American electric power system is comprised of the Western, Eastern, and ERCOT interconnections. The following discussion illustrates the attributes of the United States that present a challenge to the current and future state of the electricity system.

Resource Adequacy

Approximately 55% of the U.S. peak demand is served by organized markets such as ERCOT, NYISO, ISO-NE, MISO, PJM, SPP, and CAISO. In organized markets and elsewhere, state rules on resource adequacy may be imposed on regulated load-serving entities. This system is vastly different from the historic monopoly service model where resources were reasonably defined many years in advance by source, location, type, and ownership. Even in non-RTO areas, some load-serving entities are opting to meet resource needs by competitive acquisition of resources via a mixed portfolio of long-, medium-, and short-term contracts. Although the approach to resource adequacy by providing a sufficient supply without excess and without time to spare may not be ideal, demand is generally met on a year-by-year basis. It is, however, a challenge to be confident that this market process will work for long-term resource adequacy, given the experience of many years of deterministic resource planning. NERC's resource adequacy assessments, for example, continue to be based on reported existing, planned, and proposed resources that can be reasonably expected to be available to meet forecast demand over the long term. However, in areas with centralized markets, including those with forward capacity markets, it is sometimes difficult to determine with a high degree of certainty that resources will be available when needed. As a result, NERC's traditional approach to resource adequacy assessments may understate future resource adequacy for areas with centralized markets.

Climate Change

Fossil fuel and nuclear generation, which represent the vast majority of today's electric energy production, are facing significant economic and public relations challenges. Reliance on renewable technologies, such as wind power and solar, is necessary, and these resources are becoming more economically viable than they have been in the past. However, as intermittent resources, wind and solar are limited in their ability to meet capacity needs. Climate change initiatives are likely to impose restrictions on the operation of existing fossil fuel generation resources, which produce at greater capacity. These limitations will affect resource adequacy on several fronts: maintaining existing resources, some of which may become uneconomic to operate in a carbon-constrained world, while adding sufficient new resources to meet demand growth; providing traditional, dispatchable resources necessary to support the use of increasing amounts of renewable energy resources; and tapping demand-side resources.

Understanding the inter-reliance between new variable generation, demand-side resources, and the support they will need from traditional resources is essential to sustaining a reliable and adequate electricity supply. However, the details of how this balance will be sustained technically, economically, and environmentally are still under debate. Further, it is not clear that planning assumptions based on the operational performance of traditional resources will be valid in an environment with a significant amount of intermittent resources. These assumptions need to be tested and revalidated to ensure that the planned system is one that operators will be able to control with the same degree of reliability as in the past.

Realizing the Potential of Demand Response / Load Management

Demand response / load management is a low-cost resource that should be maximized, but its full potential is currently unknown. The impact of demand response / load management on long-term planning may be significant, but experience with these programs is still limited. As demand response / load management programs begin to make up a larger fraction of total resources, the number of annual hours in which consumer service is interrupted will increase. At some point, the unwillingness of consumers to shift the timing of their energy use or be interrupted for more hours of the year may limit the contribution of this resource to the overall resource mix.

Transmission: The Critical Link

New long-distance transmission lines are needed to bring electricity from remote renewable energy resources to load centers. These transmission lines are likely to cross some combination of state boundaries, state parks, national forests, tribal lands, and agricultural and residential areas. The existing regulatory policies, procedures, and requirements regarding transmission siting are fragmented and time-consuming. This exposes the national grid to limitations that, if left unattended, could lead to serious problems. The situation has been characterized for many years as the need for more coordinated planning, as if lack of planning by itself is the source of the difficulty. In fact, the transmission problem originates with debates about the need for a project, determining its beneficiaries, siting it, and allocating its costs. In the case of regional transmission facilities, these issues are proving extremely difficult to resolve.
Even with good intentions, the mandate of state regulators is to protect the interests of the citizens of the particular state. Regulators in adjacent states may disagree about the merits of an interstate transmission project. While transmission represents a small portion of the average consumer's bill, identifying the probable beneficiaries of a specific transmission project for a specific period of time and allocating the costs among those potential beneficiaries continues to be a difficult process with uncertain, and, in some cases, unsatisfying results.

Application of New Technology

Technological innovation is leading to the development of many applications that have the potential to achieve a Smart Grid, which could help address some of the issues identified above. However, technology development is currently ahead of its practical application and the development of the policies needed to ensure its effective deployment. This new technology has the potential to benefit the entire electricity sector from wholesale to retail consumers and from transmission to distribution, regardless of where it is deployed. However, the potential widespread use of a Smart Grid creates a considerable challenge for traditional federal and state jurisdiction and necessitates flexible and innovative approaches to regulation, cost allocation, and cost recovery.

The cost/benefit analysis used to assess the value of new technologies must be expanded beyond the typical benefit/cost evaluation of retail electric consumers and take into account broader societal values, such as reducing CO_2 emissions.

The Human "Infrastructure" Challenge

Both the educational institutions and the trained workforce required to meet the challenge of keeping the lights on in the future are lacking. The education system serving the U.S. electricity sector has withered over the years, and the nation has a diminishing pool of high-caliber technical experts needed to develop and implement the necessary tools and technologies. If the nation does not find effective solutions to this problem, it is very hard to see how the United States will be able to provide a sustainable, reliable, and adequate electric service in the future.

Chapter 2 Demand-Side Resources

Demand-side resources serve resource adequacy needs by reducing load, which reduces the need for additional generation. Typically these resources result from one of two methods of reducing load: energy efficiency or demand response / load management. The energy efficiency method designs and deploys technologies and design practices that reduce energy use while delivering the same service (light, heat, etc.) The demand response / load management method encourages consumers to reduce their electricity consumption, particularly during times of high demand, and commonly involves reduced service during these times.

For more than two decades, many utilities have employed demand-side resource programs to help manage energy supply. Although currently these resources constitute a multibillion dollar industry,[49] an increased focus on the development and use of demand-side resources is critical to meeting the nation's growing demand for electricity.

Furthermore, demand-side resources will be a key strategy in the electricity sector for addressing widespread concern about global warming and a growing consensus about the need to dramatically reduce greenhouse gas (GHG) emissions.

[49] Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

2.1 Trends, Drivers, and Potential

To establish a foundation for this discussion and the recommendations that follow, it is useful to first discuss recent trends and current drivers relating to demand-side resources and remaining demand-side potential. The sections below discuss trends relating to investments, savings, and policies, as well as the role of environmental, economic, and reliability drivers. These sections culminate in a discussion of future demand-side potential.

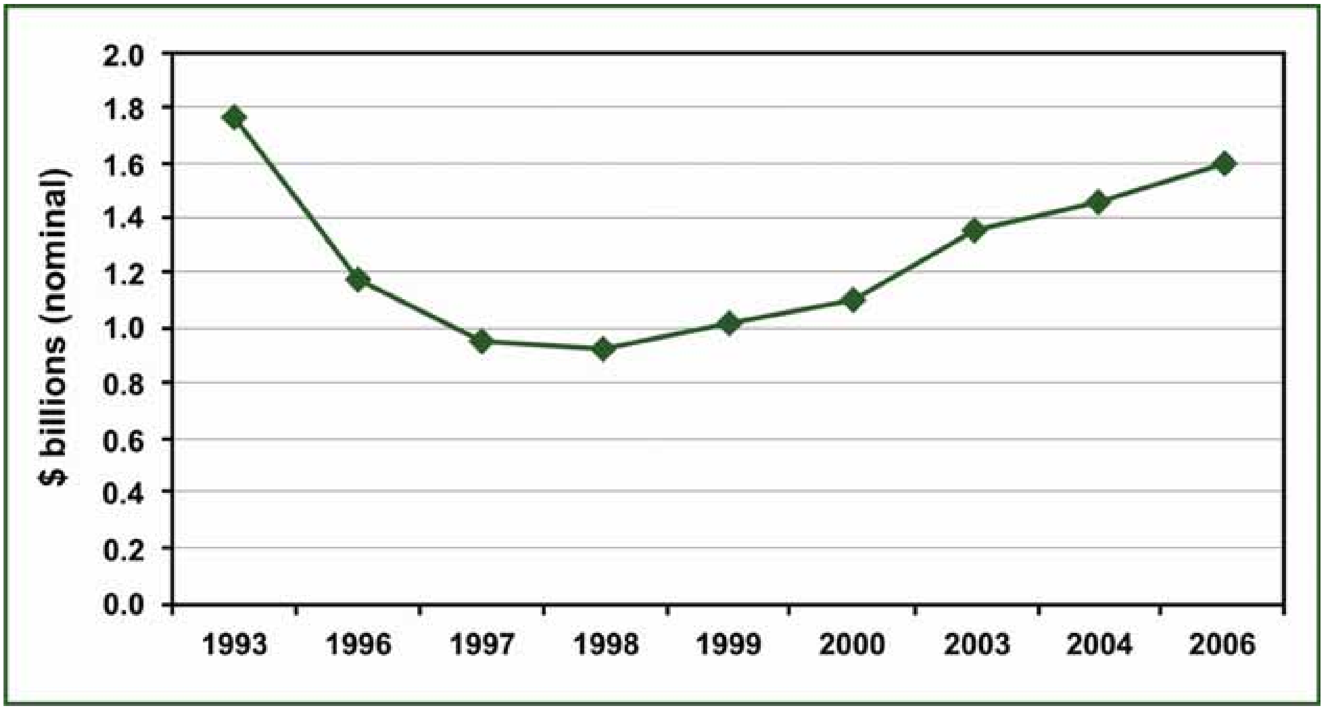
Investment Growth

Interest in demand-side resource programs gradually grew in the 1980s and early 1990s, with a decline in the mid-1990s when many states and utilities cut back on their demand-side efforts to prepare for electric industry restructuring. Growth resumed in the late 1990s as many states decided not to restructure, and even those that did decided to create mechanisms to fund and provide such programs.[50] As a result, between 1989 and 1999, U.S. electric utilities spent $14.7 billion (an average $1.3 billion per year) on demand-side programs.[51]

[50] Most notably, "public benefits" programs, which in some cases are administered and implemented by non-utility organizations. M. Kushler, D. York, and P. Witte, *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, ACEEE Report U042 (Washington, DC: American Council for an Energy-Efficient Economy, 2004).

[51] David S. Loughran and Jonathan Kulick, "Demand-side Management and Energy Efficiency in the United States," *The Energy Journal*, January 2004.

Figure 2-1. Annual Utility Sector Spending on Energy Efficiency Programs, 1993–2006



Source: American Council for an Energy-Efficient Economy 2007.[52]

Since the turn of the century, investments in demand-side resources have steadily increased. In 2006, spending on electric energy efficiency programs (both utility and non-utility programs) totaled $1.6 billion (see Figure 2-1).[53] In 2007, the Consortium for Energy Efficiency estimated that spending on electric demand-side programs increased 14% relative to 2006.[54] Furthermore, in 2007 and 2008, many states directed their utilities to substantially expand demand-side programs[55]—a decision that should lead to budget growth in future years.

State and Regional Increases in Energy and Demand Savings

As spending on demand-side programs has grown, so have energy savings. Cumulative annual savings from electric energy efficiency programs in 2006 was nearly 90 terawatt-hours (TWh) or 2.4% of total electricity sales to end-users in 2006.[56] Some states

[52] Eldridge and others, *The 2006 State Energy Efficiency Scorecard*, ACEEE Report E075 (Washington, DC: American Council for an Energy-Efficient Economy, 2007). 2006 data is included from Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

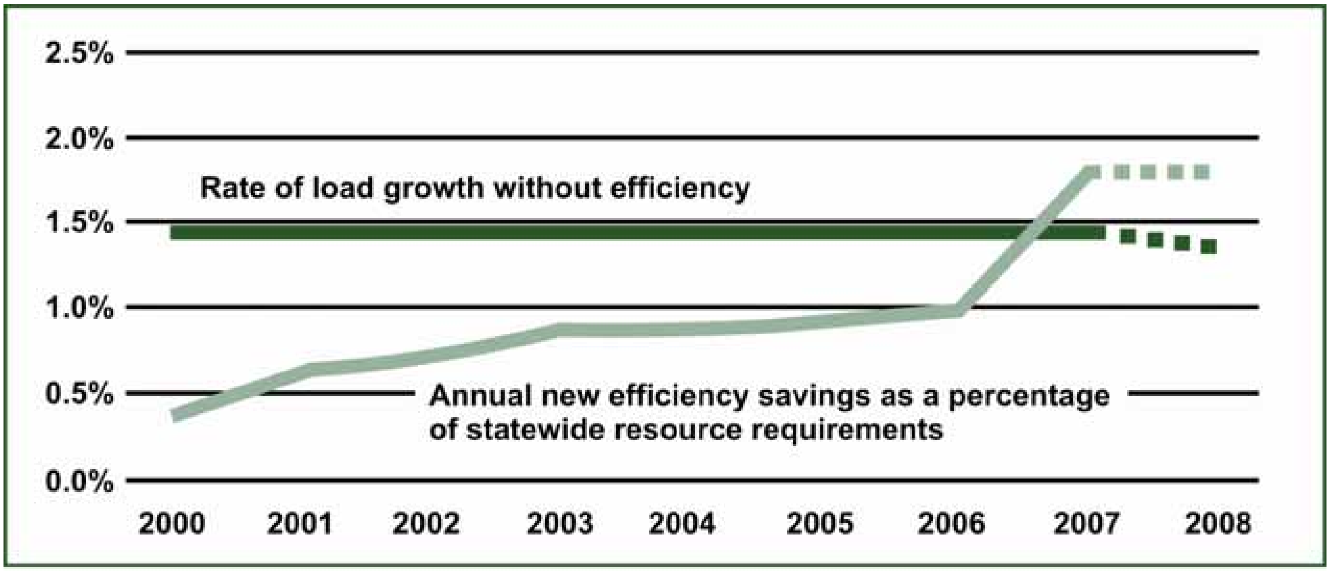
[53] This number is lower than estimates for 2006 spending previously published by the Consortium for Energy Efficiency (CEE 2007) since CEE collected data on estimated spending and the ACEEE data was collected on actual spending. Such spending in some key states, particularly California, was significantly lower than budgeted (estimated). Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[54] Consortium for Energy Efficiency, *U.S. Energy Efficiency Programs: A $2.6 Billion Industry* (Boston, MA: Consortium for Energy Efficiency, 2006), http://www.cee1.org/ee-pe/cee_budget_report.pdf.; Consortium for Energy Efficiency, *Energy Efficiency Programs: A $3.1 Billion U.S. and Canadian Industry* (Boston, MA: Consortium for Energy Efficiency, 2007). CEE's total estimates include natural gas, low-income, and load-management programs—three types of programs not included in ACEEE's national estimates (electric energy efficiency programs only).

[55] For example, legislation encouraging or mandating energy efficiency programs has been enacted in the past two years in Colorado, Connecticut, Delaware, Florida, Illinois, Maryland, Massachusetts, Michigan, Minnesota, New Jersey, New Mexico, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Washington. Michigan and Pennsylvania enacted new laws in October 2008. See American Council for an Energy-Efficient Economy, "State Energy Efficiency Resource Standard Activity" (Washington DC: American Council for an Energy-Efficient Economy, November 2008), http://aceee.org/energy/state/policies/State_EERS%20Summary_11-12-08.pdf.

[56] Daniel York (American Council for an Energy-Efficient Economy), in discussion with Steven Nadel (American Council for an Energy-Efficient Economy), October 15, 2008. (Discussion documented in forthcoming ACEEE report on utility energy efficiency program savings.)

Figure 2-2. Vertmont Energy Savings vs. Load Growth, 2000–2008



Note: 2008 values are forecasted.

Source: Efficiency Vermont 2007.[57]

are currently achieving savings of 7%–8% or more due to these programs, constituting a significant utility resource.[58] These are savings in 2006 achieved as a result of programs operating over multiple years. Programs operated in 2006 alone reduced energy use by about 8 TWh, an average of 0.2% of 2006 retail electric sales, with program costs in 2006 representing about 0.5% of total utility revenues nationwide.[59]

Collectively, electric energy efficiency and demand response / load management programs have also achieved significant levels of demand savings. The Energy Information Administration (EIA) estimates that in 2006, these programs together reduced peak demand in the United States by 27,240 megawatts (MW), of which 59% came from energy efficiency programs and 41% came from demand response / load management programs.[60]

A growing number of states are recognizing the savings benefits of instituting demand-side resource programs. These tend to be states in which regulators have adopted schemes to make demand-side investments at least revenue-neutral, if not profitable, to utility shareholders.[61] For example, during 2000–2007, Vermont reduced electricity sales by about 7%; in 2007, demand-side savings completely offset load growth (see Figure 2-2).[62] Also, in California, programs have operated for more than 20 years, leveling load per capita. California law requires energy efficiency and demand response / load management to be pursued before new supply resources can be built (see Figure 2-3). In Minnesota, programs have also been operating for close to two decades and are saving more than 0.5% per year annually.[63]

[57] *Efficiency Vermont 2007 Highlights* (Burlington, VT: Efficiency Vermont, 2008), http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.

[58] Daniel York (American Council for an Energy-Efficient Economy), in discussion with Steven Nadel (American Council for an Energy-Efficient Economy), October 15, 2008. (Discussion documented in forthcoming ACEEE report on utility energy efficiency program savings.)

[59] Ibid.

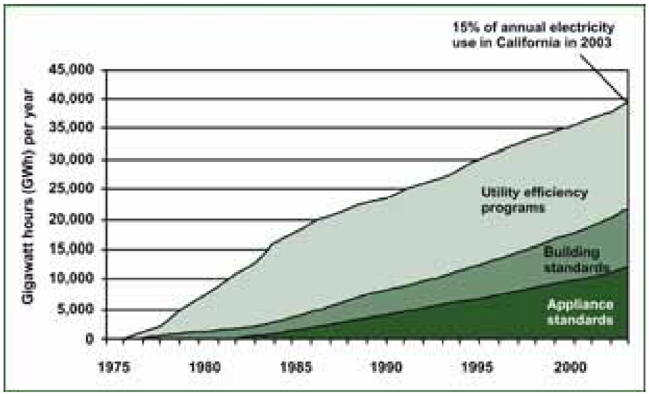
[60] Energy Information Administration, Office of Coal, Nuclear, Electric and Alternative Fuels, *Electric Power Annual 2006* (Washington, DC: Energy Information Administration, 2007), 5, table 9.1, http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf.

[61] Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[62] *Efficiency Vermont 2007 Highlights* (Burlington, VT: Efficiency Vermont, 2008), http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.

[63] Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

Figure 2-3. Electric Savings from California's Energy Efficiency Programs, 1976–2003

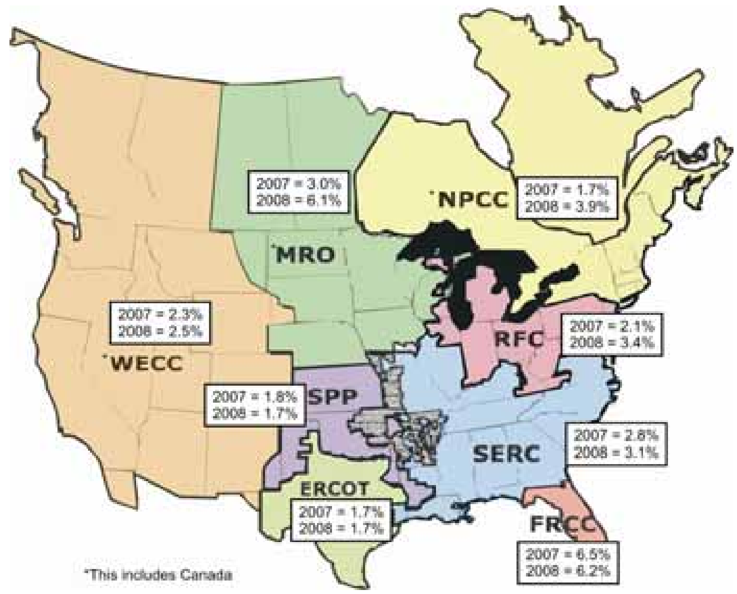


Source: American Physical Society 2008.[64]

In 2007, Vermont and California also reduced electricity sales through their programs by about 1.75%.[65] Another 13 states saved 0.5% or more in 2006 (Connecticut, Hawaii, Idaho, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New York, Oregon, Rhode Island, and Washington). The average state, however, reduced sales only about 0.2% from 2006 programs.[66] Much more needs to be done to raise the rest of the states up to at least the 0.5% savings per year level and to get leading states to 1%–1.5% per year or more.

Similarly, savings from demand response / load management programs are also increasing but vary substantially between states and regions. The Federal Energy Regulatory Commission (FERC) estimates that the demand response / load management resource in 2008 ranged from 1.7% of internal demand in the Electric Reliability Council

Figure 2-4. Demand Response / Load Management Resource in 2007–2008 as a Percent of Total Internal Demand



Source: Federal Energy Regulatory Commission 2008.[67]

of Texas (ERCOT) and the Southwest Power Pool (SPP), primarily Oklahoma and Nebraska, to more than 6% of demand in the Florida Reliability Coordinating Council (FRCC) and the Midwest Reliability Organization (MRO). The resource was much larger in 2008 than 2007 in several key regions (see Figure 2-4).[68]

Increasing Policy Support

As more states adopt demand-side resource programs, policy support for these programs at the state level has also been on the rise. In addition to California's inclusion of demand-side resources as a key element in the state's climate plan, Minnesota enacted a new law in 2007 that directs electric and gas utilities to ramp up demand-side savings to 1.5% per year. Seventeen other states have also adopted mandatory targets.[69] While these future goals are often ambitious, and in many states have not yet

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[64] American Physical Society, *Energy Future: Think Efficiency* (American Physical Society, September 2008), 68, http://www.aps.org/energyefficiencyreport/report/aps-energyreport.pdf.

[65] *Efficiency Vermont 2007 Highlights* (Burlington, VT: Efficiency Vermont, 2008), http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.; California Public Utilities Commission, "Energy Efficiency Groupware Application," *EEGA 2006 Energy Efficiency Programs Reports Submittal*, http://eega2006.cpuc.ca.gov/. The calculation is based on measures installed in 2007.

[66] Eldridge and others, *The 2008 State Energy Efficiency Scorecard*, ACEEE Report E086 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[67] Federal Energy Regulatory Commission, "2008 Summer Market and Reliability Assessment, Item No.: A-3" (Federal Energy Regulatory Commission, May 2008), 5, http://www.ferc.gov/market-oversight/mkt-views/2008/05-15-08.pdf.

[68] Federal Energy Regulatory Commission, *2008 Summer Market and Reliability Assessment* (Washington, DC: Federal Energy Regulatory Commission, May 15, 2008), http://www.ferc.gov/market-oversight/mkt-views/2008/05-15-08.pdf.

[69] American Council for an Energy-Efficient Economy, "State Energy Efficiency Resource Standard Activity" (Washington DC: American Council for an Energy-Efficient Economy, November 2008), http://aceee.org/energy/state/policies/State_EERS%20Summary_11-12-08.pdf.

been achieved on the ground, initial experience in states that have implemented such goals shows that the goals can be met.[70] This goal-setting has also encouraged other states to embark on major expansions of their programs.

Complementary Policies

At the federal level, there have also been a variety of policy efforts that have had a substantial influence on energy efficiency. For example, Congress has adopted appliance and efficiency standards on more than 40 products, ranging from incandescent light bulbs to refrigerators to industrial motors, which the U.S. Department of Energy (DOE) periodically revises. Collectively, standards adopted to date are reducing U.S. electricity use by about 10%.[71]

Likewise, states and municipalities have adopted energy codes for new and substantially remodeled buildings. DOE helps support the development of national model codes that many states adopt and also provides technical assistance and some grant funding for state code adoption and implementation efforts. An analysis prepared in 2004 for the National Commission on Energy Policy (NCEP) estimates that these codes reduced U.S. electricity use in 2000 by more than 30 billion kilowatt hours (kWh).[72] DOE also funds extensive research and development (R&D) on new energy efficiency and demand response / load management technologies. A 2001 report prepared by a National Academy of Sciences panel estimated that just a few of the most successful initiatives are saving about 1 quadrillion British thermal units (Btu) per year, or about 1% of U.S. energy use.[73] Overall, these other initiatives have most likely saved substantially more energy in the past than utility energy efficiency and demand response / load management programs,[74] although as utility programs ramp up, they are likely to become the largest energy efficiency effort, as is the case in California (see Figure 2-3). Still, it is important to consider utility programs in the context of a broad array of energy efficiency policies and programs.

Driving Factors

There are a number of factors driving this growing investment in and support for demand-side resources:

- **Environmental concerns**—Environmental concerns include global climate change, emissions of currently regulated criteria pollutants, and energy-facility siting issues. With an increasing scientific consensus that the earth is warming, many states are using energy efficiency programs as a key strategy for reducing GHG emissions. Some states, such as Texas, are using these programs as a key part of efforts to reduce nitrogen oxide (NO_x) emissions and to come into compliance with the Clean Air Act (CAA). Within states, opponents to specific power plants and transmission lines are also touting demand-side resource alternatives (e.g., Virginia and Vermont).
- **Economic factors**—A 2004 study examining the results of demand-side program evaluations in six states found that the average energy efficiency program cost approximately 3¢ per kWh saved over its lifetime (levelized cost).[75] By comparison, conventional electricity supplies are becoming more expensive, driven by rising construction and fuel costs. The EIA's 2008 *Annual Energy Outlook* notes that construction costs have risen by 50% or more in recent years and new power plants will cost more than 6¢ per

[70] American Council for an Energy-Efficient Economy, "Energy Efficiency Resource Standards Around the U.S. and the World" (Washington DC: American Council for an Energy-Efficient Economy, September 2007), http://aceee.org/energy/state/policies/6pgEERS.pdf.

[71] American Council for an Energy-Efficient Economy, "Energy, Economic and Emissions Savings from U.S. Standards" (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[72] Steven Nadel, "Supplementary Information on Energy Efficiency for the National Commission on Energy Policy" (Washington, DC: American Council for an Energy-Efficient Economy, 2004), http://www.bipartisanpolicy.org/files/news/finalReport/III.2.c%20%20Supplemental%20Info%20on%20EE.pdf.

[73] National Research Council, *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000* (Washington, DC: National Academy Press, 2001).

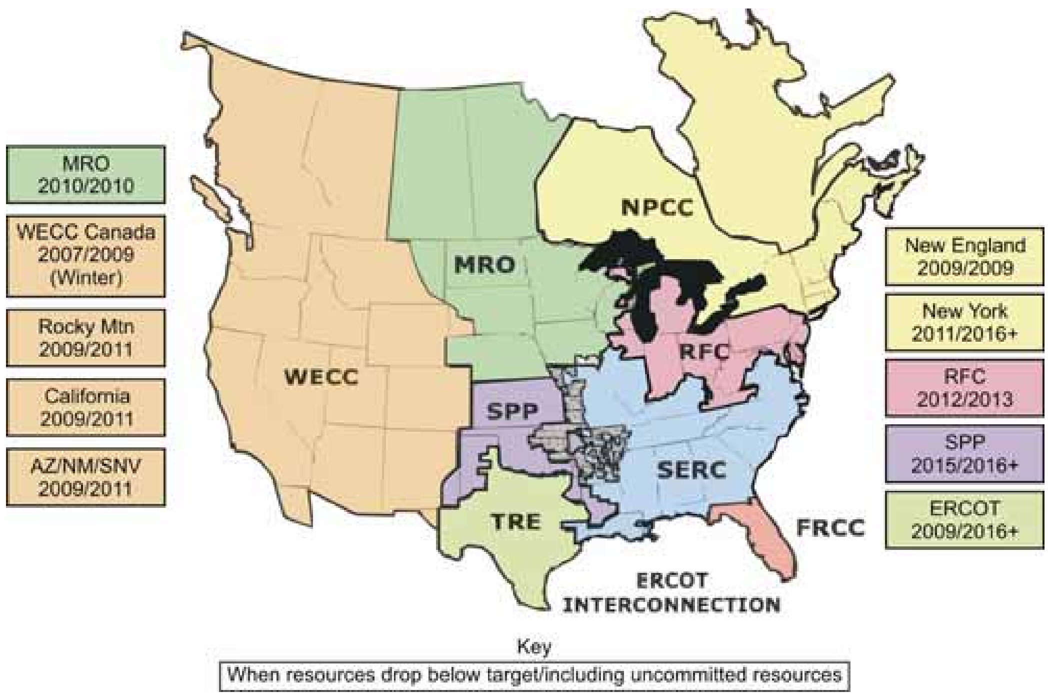
[74] Steven Nadel, "Supplementary Information on Energy Efficiency for the National Commission on Energy Policy" (Washington, DC: American Council for an Energy-Efficient Economy, 2004), http://www.bipartisanpolicy.org/files/news/finalReport/III.2.c%20-%20Supplemental%20Info%20on%20EE.pdf.

[75] M. Kushler, D. York, and P. Witte, *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, ACEEE Report U042 (Washington, DC: American Council for an Energy-Efficient Economy, 2004). Levelized cost is the average annual cost of a measure, amortized over the measure life, divided by annual energy savings.

kWh.[76] Other analysts are projecting higher costs. For example, Lazard Associates, in a presentation to the National Association of Regulatory Utility Commissioners (NARUC), found that new conventional baseload production sources generate electricity at a rate between 7.3¢ and 13.5¢ per kWh.[77] For peak electric supply, the comparison is also dramatic. When power demand peaks, many power pools are finding that marginal supplies can cost 40¢ per kWh or more, with spikes as high as $4 per kWh being reported.[78] By comparison, demand response / load management strategies can range in cost, depending on the program, from just a few cents to perhaps as much as 25¢ per kWh.[79] However, while many efficiency and demand response / load management programs are cost-effective, not all programs are. There is still some debate about the cost-effectiveness of specific programs.

- **Reliability concerns**—Reliability concerns have been used to justify both demand-side and supply-side resources. The North American Electric Reliability Corporation (NERC) projects that new resources will be needed over the 2009–2011 period in California, New England, Texas, the Southwest, and the Rocky Mountain states, and over the 2012–2013 period in the Midwest (see Figure 2-5). Large power plants can take 8–10 years to build, so where resource needs are more imminent, either gas-fired power plants (which can be built as quickly as 3 years) or demand-side resources (which, in

Figure 2-5. Year When New Power Resources Are Needed



Source: North American Electric Reliability Corporation 2007.[80]

[76] Energy Information Administration, *Annual Energy Outlook* (Washington, DC: Energy Information Administration, 2008), http://www.eia.doe.gov/oiaf/archive/aeo08/index.html.
[77] Lazard Associates, *Levelized Cost of Energy Analysis – Version 2.0*, June 2008, http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf.
[78] R. Smith, "Deregulation Jolts Texas Electric Bills," *Wall Street Journal*, sec. A1, July 17, 2008.
[79] The high end of this range can apply to standby generation programs in which owners of standby generators are paid $0.20/kWh or more for taking load off the grid during critical peak periods and serving these loads with backup (standby) generators.
[80] North American Electric Reliability Corporation, *2007 Long-Term Reliability Assessment: 2007–2016* (Princeton, NJ: North American Electric Reliability Corporation, 2007).

Table 2-1. Meta-Analysis of Electricity Energy Efficiency Potential Study Results

Region of Study	Total Efficiency Potential over Study Time Period (%)			Study Time Period (years)	Average Annual Efficiency Potential (%)		
	Technical	Economic	Achievable		Technical	Economic	Achievable
U.S. (Interlaboratory Working Group 2000)	NA	NA	24%	20	NA	NA	1.2%
Massachusetts (RLW 2001)	NA	24%	NA	5	NA	4.8%	NA
California (Xenergy/EF 2002)	18%	13%	10%	10	1.8%	1.3%	1.0%
Southwest (SWEEP 2002)	NA	NA	33%	17	NA	NA	1.9%
New York (NYSERDA/OE 2003)	36%	27%	NA	20	1.8%	1.4%	NA
Oregon (Ecotope 2003)	31%	NA	NA	10	3.1%	NA	NA
Puget (2003)	35%	19%	11%	20	1.8%	1.0%	0.6%
Vermont (Optimal 2003)	NA	NA	31%	10	NA	NA	3.1%
Quebec (Optimal 2004)	NA	NA	32%	8	NA	NA	4.0%
New Jersey (Kema 2004)	23%	17%	11%	16	1.4%	1.1%	0.7%
Connecticut (GDS 2004)	24%	13%	NA	10	2.4%	1.3%	NA
New England (Optimal 2005)	NA	NA	23%	10	NA	NA	2.3%
Northwest (NW Council 2005)	25%	17%	13%	20	1.3%	0.9%	0.6%
Georgia (ICF 2005)	29%	20%	9%	10	2.9%	2.0%	0.9%
Wisconsin (ECW 2005)	NA	NA	4%	5	NA	NA	0.7%
California (Itron 2006)	21%	17%	8%	13	1.6%	1.3%	0.6%
North Carolina (GDS 2006)	33%	20%	14%	10	3.3%	2.0%	1.4%
Florida (ACEEE 2007)	NA	25%	20%	15	NA	1.7%	1.3%
Texas (ACEEE 2007)	NA	30%	18%	15	NA	2.0%	1.2%
Utah (SWEEP 2007)	NA	NA	26%	15	NA	NA	1.7%
Vermont (GDS 2007)	35%	22%	19%	10	3.5%	2.2%	1.9%
Average	NA	NA	NA	12.8	2.3%	1.8%	1.5%
Median	29%	20%	18%				

Note: “Technical potential” are measures that are technologically possible to implement without regard to cost effectiveness. “Economic potential” is a subset of technical potential and is limited to measures that are cost effective (although the definition of “cost effective” varies from study to study.) “Achievable potential” is what can actually be achieved as a result of specific programs, policies, and implementation rates.

Source: American Council for an Energy-Efficient Economy 2008.[81]

an emergency, can produce substantial savings in one year[82] or can enable savings to steadily compound over several years[83]) will be needed.

Future Potential

With environmental and reliability concerns and economic issues continuing to drive growth, a key question remains: what is the potential quantity of demand-side resources in the future? More than a dozen studies at the state or utility level have been conducted in recent years to attempt to answer this question. Table 2-1 summarizes the results of these studies.

Overall, these studies indicate that the median achievable efficiency potential[84] is 18% over an approximately 13-year period. Efficiency potential tends to vary strongly as a function of the number of

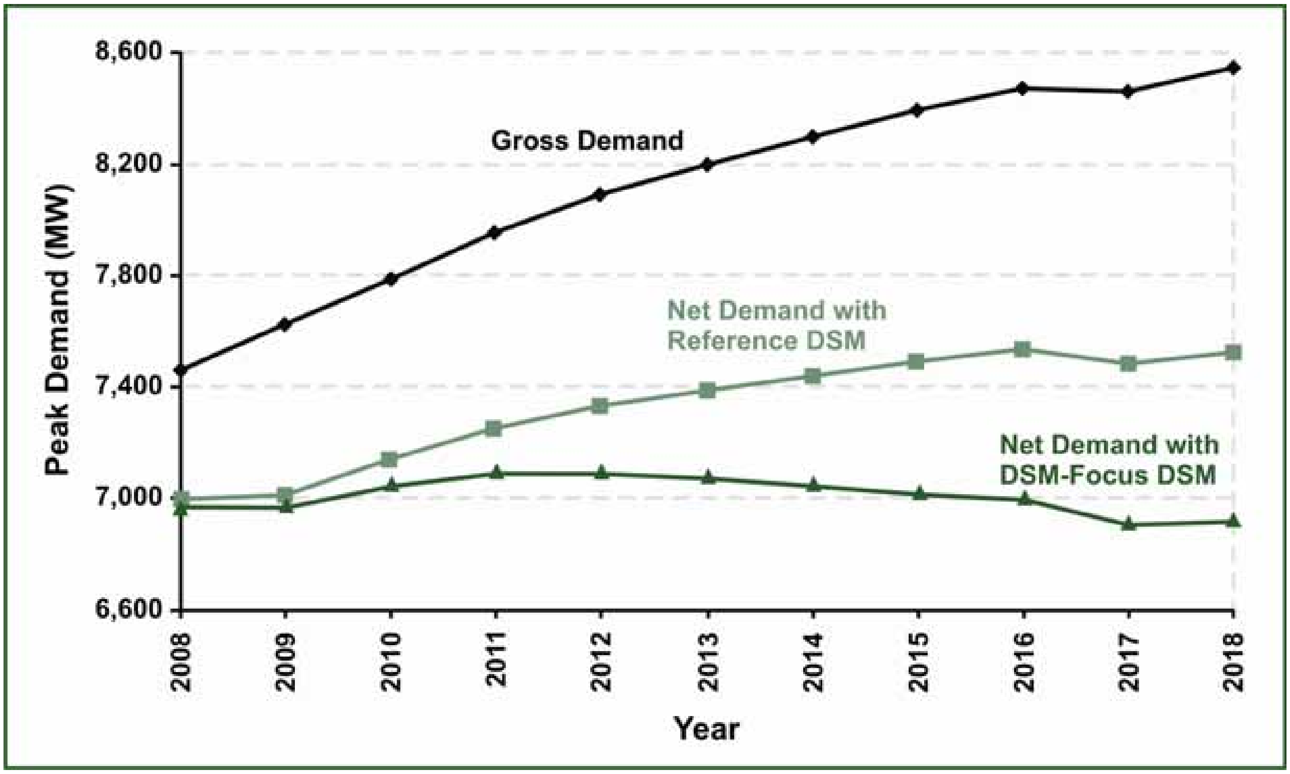
[81] Maggie Eldridge, R. Neal Elliot, and Max Neubauer, *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned*, Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings (Washington DC: American Council for an Energy-Efficient Economy, 2008).

[82] For example, during the 2001 electricity crisis, California demand-side efforts reduced peak demand by 10% and electricity sales by 6.7%. Martin Kushler and Edward Vine, *Examining California's Energy Efficiency Policy Response to the 2000/2001 Electricity Crisis: Practical Lessons Learned Regarding Policies, Administration, and Implementation*, ACEEE Report U033 (Washington, DC: American Council for an Energy-Efficient Economy, 2003).

[83] For example, Vermont has ramped up programs beginning in 2000, and by 2007 had reduced sales approximately 7% relative to what sales would have been without these programs. See *Efficiency Vermont 2007 Highlights* (Burlington, VT: Efficiency Vermont, 2008), http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.

[84] See note under Table 2-1 for a definition of this term.

Figure 2-6. Connecticut Peak Demand (in MW) Forecast under Different Demand-Side Management (DSM) Scenarios



Source: The Brattle Group, Connecticut Light & Power, and The United Illuminating Company 2008.[85]

years in the analysis; over long time periods, most existing equipment is replaced and opportunities for cost-effective savings are greater.[86] These studies also indicate that the average achievable potential per year of program implementation is about 1.5%, in line with today's most aggressive programs (about 1.7%) and much greater than the approximately 0.2% per year savings that are being achieved on average nationwide.[87] In other words, current efficiency programs are barely scratching the surface of what is potentially achievable. Additionally, average load growth in the United States is approximately 1.1%,[88] implying that in many areas, aggressive demand-side resource procurement could offset load growth. Vermont is already doing this and Connecticut is planning to do so shortly (see Figures 2-6 and 2-7).[89]

Some observers believe that estimating the market potential for energy efficiency is not a useful exercise because the estimates are often taken out of

[85] The Brattle Group, Connecticut Light & Power, and The United Illuminating Company, *Integrated Resource Plan for Connecticut* (The Brattle Group, Connecticut Light & Power, and The United Illuminating Company, January 1, 2008), http://www.ctenergy.org/pdf/REVIRP.pdf.

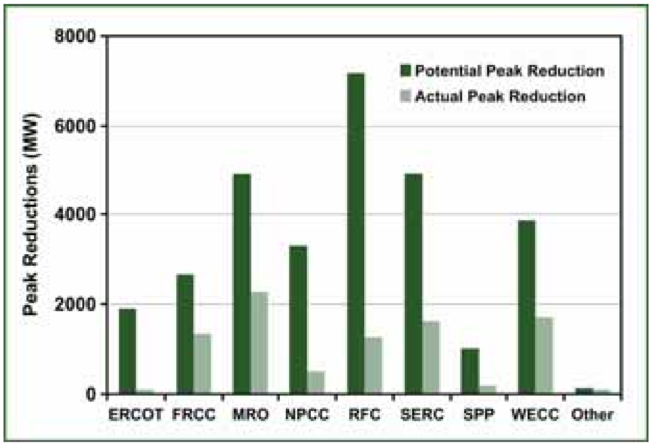
[86] Many efficiency measures are cost-effective when equipment is replaced, since the cost of efficiency is only the increment between average-efficiency and high-efficiency equipment. Steven Nadel and Howard Geller, *Smart Energy Policies: Saving Money and Reducing Pollutant Emissions Through Greater Energy Efficiency*, ACEEE Report E012 (Washington, DC: American Council for an Energy-Efficient Economy, 2001).

[87] For an example of an aggressive program, see Efficiency Vermont, *Efficiency Vermont 2007 Highlights* (Burlington, VT: Efficiency Vermont, 2008), http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf. Nationwide savings obtained from Daniel York (American Council for an Energy-Efficient Economy), in discussion with Steven Nadel (American Council for an Energy-Efficient Economy), October 15, 2008. (Discussion documented in forthcoming ACEEE report on utility energy efficiency program savings.)

[88] Energy Information Administration, *Electric Power Annual* (Energy Information Administration, 2007), table 7.2, http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html. This is both the projected load growth from 2008–2030 (Energy Information Administration, *Annual Energy Outlook*, 2008) and the average growth rate over the 2000–2006 period.

[89] K. Galbraith, "Energy Efficiency the Green Mountain Way," *New York Times*, October 8, 2008; Connecticut Light & Power, United Illuminating Company, and the Brattle Group, *Integrated Resource Plan for Connecticut*, prepared for the Connecticut Energy Advisory Board, January 1, 2008, http://www.ctsavesenergy.org/files/IRP_CLP_UI1.pdf.

Figure 2-7. Demand Response / Load Management Resource Potential Versus Actual Deployed Demand Response / Load Management Resources by Region



Source: Federal Energy Regulatory Commission 2006.[90]

context and politicized.[91] They argue that the credibility of the estimates also suffers from the fact that past efforts were not subject to measurement and verification methodologies that had broad industry support, making any determination of "cost effectiveness" speculative and a poor basis for estimating future cost effectiveness potential. On the other hand, some observers believe these results are much too conservative.[92]

A similarly thorough analysis of potential savings from demand response / load management programs has not been compiled yet, but some estimates have been attempted. A FERC report to Congress in 2006 estimated a strong potential for demand response / load management in most of the NERC reliability regions, although these estimates may be understated due to a lack of independent system operator (ISO) and regional transmission organization (RTO) response to the FERC survey.[93] Analyses conducted by the American Council for an Energy-Efficient Economy (ACEEE) for Florida, Texas, Maryland, and Virginia estimate a potential peak demand savings of 7%–22%, varying primarily as a function of load duration curve and avoided costs for critical-peak, peak, and near-peak hours.[94] Preliminary results from a study by the Electric Power Research Institute (EPRI) and the Edison Electric Institute (EEI) estimate a "realistic achievable" peak demand savings of 5.8% in 2020 and 6.3% in 2030, and a "maximum achievable" peak demand savings of 7.6% in 2020 and 9.8% in 2030.[95]

Energy savings from demand response / load management are not very well determined. Findings thus far from pilot programs show that while increases and decreases in energy use fluctuate somewhat, on average the programs have little effect on energy sales.[96]

The Electricity Advisory Committee (EAC or Committee) finds that the estimates it has gathered show that there are substantial, cost-effective savings available. In order to move forward, the Committee concludes that rather than spending time determining the exact size of the resource, that efforts to tap this resource should be increased, as long as such resource options remain cost effective. The experience gained in initial efforts to increase implementation of demand-side resources will provide additional information on the ultimate potential of these demand-side resources.

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[90] Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering* (Washington DC: Federal Energy Regulatory Commission, August 2006), http://www.ferc.gov/legal/staff-reports/demand-response.pdf.

[91] See Robert N. Stavins, Judson Jaffe, and Todd Schatzki, "Too Good to be True? An Examination of Three Economic Assessments of California Climate Change Policy," JFK School of Government, Harvard University, Regulatory Policy Program, RPP-2007-01, 2007.

[92] See D. Goldstein, *Extreme Efficiency: How Far Can We Go If We Really Need To?* Proceedings of ACEEE Summer Study on Energy Efficiency in Buildings (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[93] Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering* (Washington, DC: Federal Energy Regulatory Commission, August 2006), http://www.ferc.gov/legal/staff-reports/demand-response.pdf. Graph is from page 85 of the FERC report.

[94] R. Neal Elliot and others, *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demand*, ACEEE Report E072 (Washington, DC: American Council for an Energy-Efficient Economy, 2007); Neal Elliot and others, *Texas Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*, ACEEE Report E073 (Washington, DC: American Council for an Energy-Efficient Economy, 2007); Eldridge and others, *Maryland Energy Efficiency: The First Fuel for a Clean Energy Future*, ACEEE Report E082 (Washington, DC: American Council for an Energy-Efficient Economy, 2008); Eldridge and others, *Energizing Virginia: Efficiency First*, ACEEE Report E085 (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[95] Ingrid Rohmund and others, "Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010–2030)," *2008 ACEEE Summer Study on Energy-Efficiency in Buildings* (Washington, DC: American Council for an Energy-Efficient Economy, 2008).

[96] Omar Siddiqui (Electric Power Research Institute), in discussion with Steven Nadel (American Council for an Energy-Efficiency Economy), 2008. Discussion based on EPRI research (documented in forthcoming EPRI report).

2.2 BARRIERS

As demonstrated in the past and projected for the future, demand-side resources have the potential to help manage the ever-increasing demand for electricity. Examining the barriers to achieving this potential will help ensure that the industry is prepared to utilize demand-side resources fully.

Lack of Standardized Impact Metrics for Energy Efficiency Programs

There are currently no nationally recognized standard protocols for the impact evaluation of energy efficiency programs, nor is there agreement on when and how to use specific measurement and verification approaches. Additionally, the transparency of protocols that are currently in use varies from state to state, making it difficult to ascertain which protocols are reasonable and which are not.

Impact evaluation is necessary to determine credible estimates of net savings in both energy (kWh) and capacity (kilowatts [kW]) and when those savings occur. Commonly accepted standards for baseline calculations, the estimation of net-to-gross ratios, the estimation of free-ridership and spillover effects, and persistence analysis, among others, are needed to better predict the supply of and utilize demand-side resources nationwide. Without greater attention and resources devoted to the measurement and verification of utility energy efficiency programs, it is difficult to quantify the resource value in terms of firm energy and capacity savings (kWh and kW) that allows the consideration of demand-side resources on comparable terms with generation resources. It also further complicates any attempt to identify the generation types whose outputs are reduced as well as measurement of any concomitant emissions.

In addition, the lack of consensus program metrics also prevents the definition of energy efficiency program impacts in terms of discrete, measurable, time-based products (energy, capacity, and ancillary services) that can be understood and used by system operators and system planners, and which warrant recognition by NERC. Without clear definition of these impacts, uneven efforts to integrate energy efficiency programs with resource planning and operations result. These difficulties increase as the proportion of load to be met by demand-side resources increases.

Utilities May Have an Economic Disincentive to Undertake Demand-Side Investments

Traditional rate structures for utilities often reward increased energy throughput with increased profits, while increasing energy efficiency reduces throughput and utility revenue. Many utilities can lose money, due to lost sales, when efficiency programs expand, particularly the base revenue portion of those sales.

In addition, all utilities earn a return on supply-side investments, but only a few earn a return or profits on demand-side expenditures or investments. These losses result from rate designs that are inconsistent with a utility business model that includes both supply-side and demand-side resources and also to differences and inconsistent treatment between demand-side and supply-side resources (see Section 2.3 for further discussion). While some states have addressed these issues, most have not.

State and Federal Regulations

Another critical barrier is the potential conflict between state and federal regulation of price-responsive demand response / load management programs. Although FERC regulates wholesale markets and the ISOs that operate those markets, it has no jurisdiction over retail activities. Meanwhile, state public utility commissions (PUCs) have authority over sales and service to retail consumers but no direct control over wholesale markets. While state PUCs typically oversee utility implementation of demand response / load management programs, FERC may suggest the implementation of demand response / load management programs. These costs can only be recovered if approved by state PUCs who may have no or limited say in the demand response / load management program's implementation.

In a related vein, restructuring of the electric power industry into unique components across various state and ISO boundaries can make it difficult to develop an integrated, least-cost planning process to assess alternatives to supply options.

Interstate Program Differences

Increasingly, due to utility mergers, more utilities have service areas in more than one state. Each state has its own policies, often making planning and implementing common programs across state boundaries difficult. Differences between states also make it more difficult for program contractors, trade allies, and businesses operating in multiple states to participate in programs.

While many demand-side programs have been very successful, some have not. In some states, there is a confusing array of programs, particularly where different utilities operate different programs in the same state. However, there is always room to improve programs, learning from best practice programs around the country.

Size of the Demand-Side Resources Market

Demand-side resources are typically smaller, more diverse, and geographically dispersed compared to supply-side assets. Understanding and organizing effective market-oriented approaches through these demand-side resources poses numerous challenges. A market typically favors larger, more knowledgeable participants, so the electric marketplace has been dominated by the electricity suppliers. This supplier domination leaves residential consumers, commercial businesses, and even most large energy users on the fringes of this over $300 billion market. With a very large and diverse group of constituents, demand-side resources have difficulty establishing a unifying agenda and even getting involved in the often obtuse infrastructure planning process.

Variable Program Interest

Interest in demand-side programs has ebbed and flowed over time, making it difficult to develop and sustain long-term efforts. Programs work best when they are treated as a long-term resource and this resource is gradually procured over time. When demand-side programs are run as a series of short-term efforts, it is harder to retain staff and consumer interest. Recently, with programs in many states ramping up, there is also a shortage of skilled staff to plan, implement, and evaluate programs.

Consumer Prices Do Not Always Reflect Market Prices

Ideally, electricity would follow a perfect market with a large number of knowledgeable suppliers and consumers interacting in an open and transparent process to determine electricity's price. However, electricity is a unique commodity—supply cannot readily be stored and the demand for electricity may dramatically vary hour by hour. Most residential, commercial, or even industrial consumers do not face time-varying prices that reflect the underlying time-varying cost of supply. Since their electric rates are based on average annual costs or some other regulated pricing regime, they effectively underpay for consumption during peak periods and overpay for consumption during off-peak periods. End-users who are not paying their fair share could contribute to electricity's overuse and to underinvestment in demand-side resources.

Market Predilection toward Supply-Side Solutions

Historically, the electricity market has been financially and structurally biased toward supply-side resources (e.g., building generation or transmission facilities) to balance energy supply and demand needs, while demand-side resources (e.g., large-scale deployment of demand response / load management systems) are frequently overlooked. While use of demand-side resources has grown in recent years, this growth has often happened while fighting this bias. Socializing transmission costs and allocating payments and other incentives to encourage new generation are major contributors to this bias. While FERC has favored regional flexibility through its varied transmission cost allocation schemes for the different RTOs, these approved cost allocation mechanisms still finance the development of more supply-side resources.

The electric infrastructure has also traditionally been designed from a supply-side perspective to handle the peak period (usually per hour) usage patterns of its consumers. Peak demand happens just a few times a year (typically less than 1% of the year), so the transmission, distribution, and generation assets are operating below their design capacity for a significant portion of the year. Planning and building this generation and transmission infrastructure takes years, so inherently this process requires the addition of new electric generation and transmission in large increments. Interacting with a relatively small number of existing supply-side participants still seems easier to some electric power industry participants than creating new strategies to include emerging demand-side resources.

Consumers have also leaned toward the use of supply-side resources. Relatively low and stable energy costs have enabled end-users and others to use existing, inefficient end-use energy systems without significant price consequences. Until recently, there has been minimal economic incentive to upgrade older systems to newer, more efficient systems. Even with the impact of higher energy prices, consumers may have the behavioral inclination to leave the existing systems in place or not upgrade to the recommended newer, more appropriate systems. This inertia against change leads consumers to use existing products.

Program Costs

Financing energy efficiency programs is another barrier for demand-side resources. The large capital costs required to retrofit facilities or install more efficient equipment in new buildings are first-cost problems. Consumers have limited capital resources or are unable to obtain traditional financing for these energy efficiency improvements. There are also a limited number of financial institutions providing assistance for energy efficiency projects as evidenced by the lack of energy-efficient mortgages being processed.

Companies operating in several states bemoan the often-cumbersome process of trying to implement nationwide programs through varying local, state, and federal jurisdictions. The high transaction costs for delivering and installing many small efficiency improvements across numerous facilities may thwart corporate efforts. With their internal rate-of-return thresholds and focus on core businesses, companies tend to fund projects other than energy efficiency programs.

Investment Uncertainty

Many utilities and end-users have been reluctant to invest in demand-side resources due to investment uncertainty and the allocation of their benefits. The combination of large initial capital costs and uncertainty about how many years the upgraded facility or system will be used (the payback period) prevents energy efficiency and demand response / load management systems from being installed by homeowners, property owners, and businesses. Furthermore, recent dramatic increases in utility industry capital costs, issues about siting these facilities, and uncertainties associated with carbon emissions and other issues creates an uncertain investment climate within the electric supply-side infrastructure. There now seems to be greater recognition by a growing consensus within the industry (that now includes, for example, NERC and FERC), that a combination of both supply- and demand-side resources will be essential to maintain reliability.[97]

The problem of investment uncertainty is further compounded when the developer or owner of the facility is not the occupant or user of the installed equipment. Under such circumstances, developers and owners lack a strong incentive to specify, purchase, or install energy-efficient equipment, since they are not responsible for operating expenses. This "split incentive" exists between builders and buyers as well as between property owners and tenants. Split incentives even hamper governmental and corporate decision making as different departments might be responsible for capital and operating budgets.

Lack of Understanding of Energy Efficiency Technologies

End-users, contractors, builders, developers, and others buying, installing, or even recommending energy systems might not be sufficiently aware of or lack comprehensive information about energy efficiency technologies and costs. While technology constantly changes, there is a reluctance to try newer systems that have a limited performance record. Besides apprehension about installing a "newer and better" system, designers, builders, and end-users might not even realize that other newer alternatives exist. Even if there is an awareness that alternatives exist, they may not be readily available in that region because of local code issues or because the better replacement equipment is not readily stocked.

[97] Recognizing these planning problems, FERC Order 890 attempts to include demand-side approaches in transmission providers' planning processes. Federal Energy Regulatory Commission (FERC), Order no. 890, "Preventing Undue Discrimination and Preference in Transmission Service," final rule, *Federal Register* 72, no. 50 (March 15, 2007): 12266; FERC, Order no. 890-A, "Preventing Undue Discrimination and Preference in Transmission Service," order on rehearing and clarification, *Federal Register* 73, no.11 (January 16, 2008): 2984; FERC, Order no. 890-B, "Preventing Undue Discrimination and Preference in Transmission Service," order on rehearing and clarification, *Federal Register* 73, no. 131 (July 8, 2008): 39092.

Advanced Metering

The lack of consensus on implementing an advanced metering system and measuring system also serves as a barrier to companies and state PUCs investigating the cost-effectiveness of installing these systems. Advanced metering systems could readily be incorporated into a Smart Grid system (a sophisticated two-way communication process that manages and oversees the entire grid), but the feasibility of this method is still under debate.[98]

2.3 Key Considerations

In addition to overcoming the barriers discussed above, there are a number of considerations that the electric power industry needs to explore in order to effectively develop and implement demand-side resources now and in the future. These considerations are explored below.

Integration of Demand-Side and Supply-Side Resources

Demand response / load management resources and energy efficiency strategies can be used as part of a concerted effort to meet portions of U.S. electric demand while also realizing other advantages, such as reducing GHG emissions and reducing electricity's carbon footprint. If the impacts of demand response / load management and energy efficiency programs are recognized as resources (in kW and kWh) comparable to traditional generation supply—and subject to appropriate impact evaluation protocols—then these programs should be treated on a nondiscriminatory basis in a utility's resource plan. There are currently four general approaches, which should all be considered as ways for regulated electric utilities to incorporate an integrated resource plan (IRP):

1. **Demand-side planning ("first fuel" approach)**—Adoption of targets such as "15-by-15" or "20-by-20," meaning 15% or 20% load reduction by 2015 or 2020, respectively. Such targets are generally set based on studies of the available cost-effective demand-side resource. This resource is factored into load forecasts. Demand-side programs should be evaluated, for actual savings achieved, and forecasts adjusted as needed. If demand growth is low, demand-side resources can fully offset load growth. If demand growth is higher, demand-side resources will reduce but not eliminate the need for new power supplies as well as replacement power sources when aging power plants are retired. The advantage of the demand-side planning approach is that it quickly leads to the development of demand-side resources—resources that have not received a lot of attention in many states. The disadvantage of this planning approach is that if targets are set without regard to the size of the cost-effective resource, or if programs are ineffective and not evaluated and improved, then suboptimal investment levels will result.
2. **Regulation and IRPs**—Demand-side and supply-side resources are simultaneously evaluated in the context of the long-term planning and operational needs of the utility. Such evaluations have planning horizons of varying periods, but typically extend for 10–20 years. The advantage of this approach is that all resources can be evaluated on a common basis, and the optimal amount of each resource can be selected. The disadvantage of this approach is that it can be time-consuming, particularly since IRPs are often controversial, and many details are frequently adjudicated.
3. **Market-based methods, such as competitive bidding**—Utilities' short- and long-term planning and operational needs are acquired through competitive solicitations or auctions. This approach is becoming common in FERC-jurisdictional wholesale capacity markets and in ERCOT. There is growing acceptance of demand-side resources in these markets, but when demand-side resources are bid into the market, the emphasis is on demand response / load management and improvements to very large facilities. Reluctance to accept bids from energy efficiency programs results in part from historical emphasis of such programs to save energy (kWh) and not capacity (kW). Hard-to-reach markets, such as small commercial and residential consumers (particularly multifamily housing and low-income households), are rarely bid in. The advantage of this approach is that all interested market players can participate, and prices are set by the market. The disadvantages are that cost-effective demand-side resources are frequently left on the table and that costs can be high, as bidders are generally sophisticated

[98] For more information about deployment of a Smart Grid, see *Smart Grid: Enabler of the New Energy Economy*, Electricity Advisory Committee, December 2008.

enough to estimate the market clearing price and come in with bids just below this value.[99]

4. **Supply-side planning**—Utilities plan their next generator based on long-term load forecasts that may or may not internalize demand-side effects. This type of plan may have to be done after demand-side planning, or as a standalone process. The advantage of this process is that if cost-effective demand-side resources are first maximized, supply-side decisions are frequently less controversial. The disadvantage of this approach is that demand-side resources can be ignored in some cases.

These different approaches can be integrated. For example, Connecticut has a demand-side planning target set in law of 1% savings per year, but then conducts an IRP, and through this IRP has identified additional demand-side resources to procure. They also bid out a portion of their demand-side needs.

While members of the EAC do not agree on which demand-side resource options should be promoted, all members agree that whatever demand-side resource method is implemented, it must be deployed and executed well, with demand-side resources fully considered and investments selected (both demand- and supply-side) that minimize long-term costs to ratepayers. It should be noted that a key component to the use of demand-side resources is a well-defined and standardized evaluation measurement and verification process (see Section 2.4).

Funding Demand-Side Resources

The cost of demand-side investments is generally recovered by utilities in rates. Historically, program costs are included as part of a rate case, ultimately leading to an approved set of costs that are allocated to all consumer classes through the normal rate case process. Alternatively, in the 1990s, it became common to pay for energy efficiency programs through a special per kWh "system benefit charge" or "public benefit fund" that is added to electric rates. Many of these riders are still in effect, although in recent years the historic rate case approach has again begun to dominate.

Despite the fact that demand-side resource programs have been implemented for three decades, there remains considerable debate on how the costs of energy efficiency and demand response / load management resources should be allocated and recovered. If generators sell capacity and energy under long-term contracts or purchased-power agreements at market-based rates, it is rarely the case that demand-side resources are eligible for the same form of compensation. Thus, demand response / load management and energy efficiency costs and the allocation and recovery of generation costs are typically inconsistently determined.

The electric power industry is entering a sustained period in which demand-side resources will become a natural part of the regulated utility's business model. How to expense or allow in rate-based funds committed to energy efficiency and demand response / load management programs needs to be resolved in the context of normal rate design and cost allocation procedures. Separate ratemaking treatment, such as with special riders (e.g., system-benefit charges) or single-issue proceedings, for the purpose of adjusting rates in isolation of other costs of doing business, should generally be avoided.[100]

Historically, investments in supply-side resources were raised in capital markets and included in the rate base, allowing shareholders a reasonable opportunity to earn a recovery of and a rate of return on their investments at a level of profit commensurate to the investments' risk. Demand-side resource program costs are generally expensed and not included in the rate base. Thus, it is ratepayers who are providing the "capital" for demand-side resources. On the other hand, under this approach, ratepayers do not have to pay a rate of return on these investments, and utilities do not earn such a rate of return.

Many utilities and regulators have come to recognize that utilities can make profits by building supply-side resources, but they do not generally earn a profit

[99] Martin Kushler and Patti Witte, *Can We Just "Rely on the Market" to Provide Energy Efficiency? An Examination of the Role of Private Market Actors in an Era of Electric Utility Restructuring*, ACEEE Report U01 (Washington, DC: American Council for an Energy-Efficient Economy, 2001).

[100] Almost all state public utility commissions provide a rate case process to evaluate and measure the appropriate overall cost of service where a balanced review of jurisdictional expenses, rate base investment, the cost of capital, and revenues at present rates are investigated at a common point in time (i.e., the test period). See National Action Plan for Energy Efficiency Leadership Group, *Aligning Utility Incentives with Investment in Energy Efficiency* (Washington, DC: National Action Plan for Energy Efficiency Leadership Group, 2007), prepared by Val R. Jensen, ICF International, http://www.epa.gov/cleanenergy/documents/incentives.pdf.

from demand-side resources. This is partly because returns are only earned on capitalized investments and partly due to how utility kWh sales affect profits. One way many utilities earn profits is to increase sales beyond the level of sales assumed when rates were calculated. Rates are set to recover fixed and variable costs at the predicted sales level. However, if sales exceed the forecast, then the fixed-cost portion of rates is added profit. On the other hand, if sales are less than forecast, then fixed costs are not fully recovered and profits decline.

To address the issue of return on investments, two approaches have been used and should be considered going forward:

1. Include demand-side investments in the rate base and allow utilities to earn a return on these investments. (This approach is used in Nevada, and Florida is likely to use this approach.)
2. Provide utilities with some small profit incentive for successfully reaching or exceeding demand-side goals. Such incentives could be in the form of specific payments for achieving specific goals (e.g., x million dollars to shareholders if kWh savings goals are met[101]); a set percentage incentive for achieving a specified percentage of the savings goal[102]; or sharing the savings from the difference between demand-side and supply-side costs[103] (e.g., California utilities can now earn 9% of the net benefits from demand-side programs once they approach their demand-side goals and 12% of net benefits if they exceed their goals).[104]

To address the impact of sales on profits, there are several policy options to consider:

1. Decouple revenues from sales.[105]
2. Allow recovery of "lost revenues" in retail rates.
3. Redesign retail rates with a straight-fixed-variable (SFV) rate design to remove fixed costs from tail blocks.[106]
4. Do nothing because many electric utilities continue to experience positive growth in sales and consumer numbers regardless of the level of energy efficiency programs.

In general, the Committee supports financially remunerating utilities for undertaking demand-side initiatives and investments, proportionate with the risks. These returns need to be reasonable, with a substantial majority of demand-side benefits going to ratepayers.

2.4 Recommendations to DOE

The United States has a long tradition of relying on the market to drive results. Often, these results are based on sound economic principles that attract market participants who endeavor to capitalize on market opportunities. It is with this mindset that the EAC provides these specific recommendations to the DOE for improving the use of demand-side resources:

> **1. Place priority on expanding existing DOE programs that capture energy efficiency savings (e.g., updating federal appliance/equipment standards and national model building codes) and that help develop new energy-saving technologies and practices that can be used in future decades (e.g., R&D initiatives).**

DOE has "missed all 34 congressional deadlines for setting energy efficiency standards for the 20 product categories with statutory deadlines that have

[101] This approach is now used in Vermont. Kushler, York, and Witte, *Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Initiatives* (Washington, DC: American Council for an Energy-Efficient Economy, 2006).
[102] This approach is currently used in Massachusetts, Michigan, Nevada, Ohio, and Rhode Island. Ibid.
[103] This approach, in various forms, is used in California, Connecticut, Colorado, Georgia, Hawaii, Minnesota, New Hampshire, New Jersey, and Texas. Ibid.
[104] Public Utilities Commission of the State of California, "Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond," Order Instituting Rulemaking to Examine the commission's Future Energy Efficiency Policies, Administration and Programs. Rulemaking 01-08-028. Decision 04-09-060. September 23, 2004.
[105] See National Action Plan for Energy Efficiency, *Aligning Utility Incentives with Energy Efficiency Investment*, Prepared by Val R. Jensen, ICF International, November 2007, http://epa.gov/eeactionplan. For an alternative point of view, See Electricity Consumers Resource Council, "Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Council" (Washington, DC: Electricity Consumers Resource Council, January 2007).
[106] See David Boonin, "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements" (National Regulatory Research Institute, July 2008).

passed," according to a U.S. Government Accountability Office (GAO) report from January 2007.[107] The report further states that, "Lawrence Berkeley National Laboratory estimates that delays in setting standards for the four consumer product categories that consume the most energy—refrigerators and freezers, central air conditioners and heat pumps, water heaters, and clothes washers—will cost at least $28 billion in forgone energy savings by 2030."[108] The new DOE Secretary should give top priority to this internal DOE effort.

In addition, national model building codes, developed by the International Code Council (ICC) and the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) are now undergoing revision. ASHRAE is targeting a 30% reduction in energy use relative to the 2004 standard. The ICC recently updated its residential energy standard to reduce energy use by an average of about 13% and narrowly defeated a proposal to increase the energy savings to 30%.[109] This "30% solution" proposal is likely to be proposed again in 2009. DOE should actively support these efforts to reduce energy use in new buildings by at least 30%, including providing technical and analytic support for these efforts and testifying/commenting on behalf of cost-effective approaches that achieve these savings levels. In the longer term, DOE should provide similar support for making new buildings 50% more efficient than current codes, in line with the efficiency levels for new buildings now being promoted by federal tax incentives included in the Energy Policy Act of 2005.

DOE also has a major R&D program to develop new energy saving technologies and practices. In fiscal year 2008, energy efficiency expenditures totaled approximately $700 million.[110] Many independent panels, including the President's Committee of Advisors on Science and Technology, the National Commission on Energy Policy, and the American Physical Society, have recommended that resources devoted to energy efficiency R&D be substantially expanded, in order to help reduce energy use, costs, and emissions in the long-term and to keep the United States at the cutting edge of new technology development.[111] As programs are expanded, the Committee recommends that these efforts include increased joint R&D with utilities and states, demonstration projects, Golden Carrot programs, and other technology procurement efforts. This expanded R&D should also include research on programs and technologies that reduce energy use through changes in energy-using behavior, with a particular focus on changes that persist over time.

2. Develop national measurement and verification protocols/standards that will better measure the savings that are being achieved.

DOE should facilitate the development of measurement and verification metrics for estimating reliable resource values (kW and kWh) of mass-market energy efficiency programs, if the intent of such programs is to defer or avoid new utility infrastructure construction or obtain net reductions in GHG emissions. These protocols and standards will enable savings to be more reliably counted upon as a substitute for or as deferment of the need for new power plant construction, while also maintaining reliability. They will also help to better ensure that demand-side investments are cost-effective.

In fulfilling this objective, DOE should facilitate the development of national consensus measurement and verification protocols, standards, and business

[107] U.S. Government Accountability Office, January 2007, *Energy Efficiency, Long-standing Problems with DOE's Program for Setting Efficiency Standards Continue to Result in Forgone Energy Savings* (Washington DC: Government Accountability Office, January 2007), GAO-07-42, www.gao.gov/new.items/ d0742.pdf.
[108] Ibid.
[109] Bill Fay (Alliance to Save Energy), in discussion with Steven Nadel (American Council for an Energy-Efficiency Economy), November 25, 2008, regarding insulating concrete forms (ICF) savings analysis from 2009 International Energy Conservation Code.
[110] Alliance to Save Energy, *FY 2009 Federal Energy Efficiency Programs Funding Fact Sheet* (Washington, DC: Alliance to Save Energy, 2008), http://www.ase.org/content/article/ detail/3974.

[111] The President's Committee of Advisors on Science and Technology, *Federal Energy Research and Development Challenges of the Twenty-First Century* (Energy Research and Development Panel, 1997), 3-26; The National Commission on Energy Policy, *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges* (Washington, DC: National Commission on Energy Policy, 2004), 30.; American Physical Society *Energy Future: Think Efficiency* (American Physical Society, September 2008), Sec. 1:9, http://www.aps.org/energyefficiencyreport/report/aps-energyreport.pdf.

practices with input from a broad range of interested parties. Such an effort should build upon existing protocols and standards developed by individual states, the Northwest Power and Conservation Council (NPCC), and emerging efforts by the North American Energy Standards Board, Northeast Energy Efficiency Partnerships, and the National Action Plan for Energy Efficiency (NAPEE). Given the number of regional efforts underway, one possible path to national protocols is to first build regional protocols and then meld the different regional protocols together. DOE should also provide federal technical assistance to states and regions to participate in these efforts. Additionally, DOE should encourage the NERC to continue its efforts to refine the reporting of demand-side resources in NERC's reliability assessment activities.

3. Promote policies at the federal and state levels that can encourage expanded cost-effective energy efficiency and demand response / load management efforts, including expanding federal technical assistance to states and utilities, allowing demand resources to participate in independent system operator forward capacity markets, expanding regional coordination on demand-side resources, and developing energy-savings targets for utilities and/or state agencies.

DOE should promote policies at both the federal and state level that encourage expanded cost-effective energy efficiency and demand response / load management efforts. Specifically, the Committee recommends that DOE support the following:

- Development of utility business models and rate-setting approaches that encourage and reward cost-effective energy efficiency and demand response / load management investments while providing a substantial majority of benefits to ratepayers
- Expansion of federal technical assistance to states and utilities
- Allowance of demand resources to participate in ISO forward capacity markets
- Expansion of regional coordination on demand resources so utilities, states, other program administrators, businesses, and trade allies can more easily work across state/utility territory lines in the same region
- Development of energy-savings targets for utilities and/or state agencies that are based on sound analysis of cost-effective opportunities relative to other resource options and that fairly treat each consumer class

Develop utility business models and rate-setting approaches that encourage and reward cost-effective demand-side resources

State PUCs regulate utility operations and have tried different approaches to encourage more demand-side resource deployment. State PUCs have approved approaches that decouple utility profits from utility sales, created incentives that reward energy efficiency, and allowed utilities to recoup lost sales through a lost revenue adjustment clause. Despite these efforts, in many states utility profits can suffer if energy efficiency is promoted; therefore, these states do not maximize the potential contributions that distributed resources could contribute to the electric power delivery infrastructure.

The Committee recommends that state PUCs seriously examine these issues and introduce regulatory reforms so that utilities' financial health does not suffer when they make cost-effective investments in energy efficiency and demand response / load management. DOE can assist in these efforts by providing a coordinated strategy and guidance to help state PUCs and utilities analyze information and develop/execute strategies that will positively contribute to the overall cost-effective utilization of distributed resources. DOE may be able to capitalize on the use of its national laboratories and other resources to conduct analyses that will help determine the economic implications of regulatory options to address these issues.

Further, DOE can advocate before FERC, state PUCs, and other local regulatory bodies in favor of utility business models and ratemaking procedures that are resource neutral. DOE should advocate ratemaking procedures that allocate costs of demand-side and supply-side resources on a comparable basis, such that investments in either form of resource afford the utility a reasonable opportunity to earn a return on the investment, provided that the resource mix is least-cost to ratepayers. Ultimately, decisions will remain at the state level, but DOE can provide (perhaps by working with other associations such as NARUC, the National Regulatory Research Institute, and EEI) significant guidance and resources to evaluate potential regulatory reforms.

Expand federal technical assistance to states and utilities

In the 1990s, DOE had a substantial IRP program that worked with NARUC and other organizations to conduct research and provide technical assistance on demand-side resource issues. This effort has since shrunk to a small proportion of its prior size. DOE and the U.S. Environmental Protection Agency (EPA) also initiated NAPEE to foster the collaborative efforts of key energy market stakeholders, including utilities, regulators, energy consumers, and partnership organizations, to establish and further a national commitment to cost-effective energy efficiency and demand response / load management. The results of this commitment were meant to generate investment in energy efficiency and demand response / load management through sound and economically viable business cases, identification and implementation of best practices, and education of various audiences. Today the NAPEE program provides assistance to state regulators in the form of focused education, helping states meet their desired energy and capacity needs cleanly and efficiently. However, relative to the need for information and technical assistance, both DOE and NAPEE efforts are small and should be expanded.

The Committee recommends a major focus on working with NARUC, in which DOE provides technical assistance to states, and coordinates technical assistance efforts by others, such as the work currently underway at EPRI and EEI's Energy Efficiency Institute. Such an effort can also compile and provide information to U.S. organizations on best practice programs and policies elsewhere in the world.

As part of this effort, DOE should assist states with development of state long-term energy efficiency strategic plans that provide a comprehensive roadmap for state efforts, including mandatory codes and standards, utility or third-party programs, and private market efforts, focusing on all end-use sectors, workforce training, and marketing and education. Such a roadmap has proven very useful in California and would likely be useful in many other states.[112]

Allow demand resources to participate in ISO forward capacity markets

DOE should also advocate before FERC, RTOs, and state PUCs that any retail consumer (including aggregators of retail consumer loads) should have access to demand response / load management and forward capacity markets at either the retail or wholesale levels. Such consumers should receive appropriate payment for reducing or curtailing their loads (kW capacity) for specific time periods, subject to adequate evaluation of actual load reductions. This includes energy efficiency and demand response / load management programs and actions. Some members of the Committee prefer such access at the retail level and subject to state regulation, while other Committee members prefer access at the ISO and RTO level, subject to federal regulation.

Encourage and assist with regional coordination on demand resources so utilities, states, other program administrators, businesses, and trade allies can more easily work across state/utility territory lines in the same region

The electric power delivery infrastructure of the future seeks to maximize its utilization, increase reliability, minimize unproductive investment, and minimize its adverse impact on the environment. Demand-side resources can successfully contribute to these goals. However, in order to do so, it is necessary to establish and execute a coordinated demand resource strategy. This strategy must focus on optimizing the installation and utilization of these types of equipment. The desire to have a fully integrated electric grid that maximizes the use of its components necessitates potential demand-side resource solutions that offer independence from the jurisdictional borders established by state/utility/municipal boundaries. Accordingly, coordination (and the acceptance of a coordinated

[112] California Public Utilities Commission, *California Energy Efficiency Strategic Plan* (California Public Utilities Commission, September 2008). http://www.californiaenergyefficiency.com/docs/EEStrategicPlan.pdf.

resource strategy) among these bounded entities needs to be facilitated to ensure that demand-side resource opportunities are maximized. These efforts can be integrated with the increased technical assistance called for in the preceding recommendation. A possible model for these efforts is the work of the NPCC, which facilitates common approaches to demand-side issues in the Northwest.

Develop energy-savings targets for utilities and/or state agencies that are based on sound analysis of cost-effective opportunities relative to other resource options and that fairly treat each consumer class

As discussed earlier in this chapter, 18 states have now established energy efficiency resource standards—binding energy-saving and/or peak reduction targets that utilities (or state agencies[113]) must meet. Such targets typically start at low levels initially and gradually ramp up, allowing programs to start small and expand over time. Advocates of these targets argue, based on implementation experience to date, that these targets spur a substantial increase in energy efficiency investments and are the best way to meet targets at minimal costs. Energy-savings targets should be based on recent studies of and experience with achievable cost-effective savings. Such programs can also be structured to allow consumers to meet targets on their own, without participating in utility programs (e.g., provisions in Ohio and Michigan).[114] Many EAC members believe that DOE should encourage additional states to develop binding energy-savings targets based on these principles and should also assist and support efforts by Congress to adopt appropriate targets at the national level. Other Committee members believe that DOE should research this issue further before taking a position and that DOE should assist states to conduct such research.

[113] Of the states that have enacted such targets, Illinois, Maryland, and New York assign a minority role on implementation to state agencies. American Council for an Energy-Efficient Economy, "State Energy Efficiency Resource Standard Activity" (Washington DC: American Council for an Energy-Efficient Economy, November 2008). http://aceee.org/energy/state/policies/State_EERS%20Summary_11-12-08.pdf.
[114] See, for example, State of Michigan, *Clean, Renewable, and Efficient Energy Act*, Act No. 295, 94th Legislature, Regular Session of 2008 (October 6, 2008), http://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.

4. Research, develop, and support promising new energy efficiency policies and tools including energy-efficient mortgages, on-bill financing for energy-saving retrofits, energy performance ratings and disclosure for existing buildings, and use of energy-use feedback devices to help consumers better manage their use.

There are many additional promising policies to increase energy efficiency and better manage loads. Three such promising policies are:

- On-bill financing for energy-saving retrofits
- Energy performance ratings and disclosure for existing buildings
- Use of energy use feedback devices to provide real-time information on energy use and costs to consumers, helping them to better manage their use

On-bill financing allows consumers to easily finance energy-saving improvements and pay for them on their energy bills. Properly structured (balancing loan amount, term, and interest rate), on-bill financing will generally make it possible for consumers to realize immediate bill savings, with the value of energy savings exceeding the monthly loan payment.[115]

Building ratings and disclosure inform prospective building purchasers and renters about the energy use of a building they may purchase or lease, helping to create demand and value for efficient buildings. The EPA presently rates and labels many types of existing commercial buildings through the Energy Star program, but not all building types are covered, and a similar program would be useful for existing residences, including multifamily buildings.[116]

[115] M. Suozzo and others, *Policy Options for Improving Existing Housing Efficiency*, ACEEE Report A971 (Washington, DC: American Council for an Energy-Efficient Economy, 1997).
[116] For example, the Dingell-Boucher discussion draft bill includes language proposing labeling requirements for all building types for which statistical information is available. See U.S. House of Representatives, 110th Cong., 2nd sess., October 7, 2008, http://energycommerce.house.gov/images/stories/Documents/PDF/selected_legislation/clim08_001_xml.pdf.

Energy use feedback devices provide information to consumers on their current energy use and how it compares to their own use in earlier periods and to similar homes and buildings in their community. As a result of this feedback, short-term energy use reductions of 3%–27% have been documented, making these devices very promising.[117] Types of energy use feedback devices range from in-home displays to internet-based systems. However, little research has been conducted on changes in energy use over the long term, and more research is sorely needed. DOE should support such research.

DOE should research each of these opportunities, develop best practice approaches, and support adoption of these approaches by utilities, states, municipalities, and end-users. In some cases, DOE should coordinate with other agencies (such as EPA) on building energy performance ratings and labels.

[117] Omar Siddiqui and Bernie Neenan, "Influencing Electricity Consumption Behavior" (presentation, Energy Efficiency Public Advisory Meeting, September 25–26, 2008).

Chapter 3
Transmission Adequacy

Transmission lines are the critical link between the point of electricity generation and consumers. The U.S. transmission grid infrastructure is owned and operated by approximately 3,000 distribution utilities and 500 transmission owners. This structure presents a distinct set of challenges in transmission planning, siting, cost allocation, grid operations and control, technological innovation, financing, and construction. The development and deployment of a national strategy on transmission that meets the needs of all parties will be extremely complex; however, a solution is desperately needed.

The existing grid is strained by a rising demand for electricity, an aging and congested delivery infrastructure, and a growing interest in Smart Grid technologies, as well as the integration of renewable energy resources. Upgrading the transmission grid is essential to support future electricity delivery for two main reasons. First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers. According to Rick Sergel, President and Chief Executive Officer of the North American Electric Reliability Corporation (NERC), expedited transmission development is the key to addressing both of these issues. Sergel said, "We need more transmission resources to maintain reliability and achieve environmental goals. Transmission lines are the critical link between new generation and consumers, yet we continue to see transmission development lag behind generation additions. Faster siting, permitting, and construction of transmission resources will be vital to keeping the lights on in the coming years."[118]

3.1 Trends and Drivers

Today's aging transmission grid is a hodgepodge of individual and regional systems, costing consumers billions of dollars in congestion annually and limiting interconnection of low-carbon resources. While there are signs of advancing grid development, challenges remain with dated processes and methods for planning, permitting, and cost allocation.

Historical Evolution of the Grid

The existing interstate electric transmission network resulted from vertically integrated utilities building generation and transmission to serve their consumers' electricity demands, to provide for the wholesale purchase and sale of electricity with neighboring utilities, and to share generating capacity reserves to minimize installed capacity reserves. As the system grew, progressively higher voltages were developed to improve delivery efficiency. This system is now at an age and in a condition that requires significant upgrading or replacement of portions of original infrastructure and the addition of new infrastructure to support the United States' projected electricity future. The planning of the current system did not address the goals of broad-scale regional and interregional

[118] North American Electric Reliability Corporation, "Ten Year Outlook for Electric Reliability Highlights Environmental Initiatives, Transmission among Key Concerns," news release, October 23, 2008, http://www.nerc.com/news_pr.php?npr=186.

planning and meeting larger national needs. However, this grid system is being called on to meet the objectives of wholesale markets that have evolved in response to the passage of the Energy Policy Act of 1992 (EPAct 1992) and the growing need to integrate remote sources of renewable energy generation.

State and Regional Progress in Planning and Policy

Federal Energy Regulatory Commission (FERC) Order No. 890 calls for all transmission providers to participate in open, transparent regional planning processes. States and regional entities appear to recognize the need for broader planning. In fact, many states have been very proactive in planning for their energy future, advancing well beyond national efforts. Regional transmission organizations (RTOs) have also been proactive within their regions. For example, in the eastern United States, the Joint Coordinated System Plan (JCSP) study is currently examining transmission infrastructure development plans that would facilitate the integration of a large amount of wind energy.[119] The Midwestern Governors Association (MGA) in 2007 published a greenhouse gas (GHG) reduction platform that calls for increased attention to transmission; more recently, the Upper Midwest Transmission Development Initiative (UMTDI) was formed to identify wind power generation resources and transmission infrastructure to support those resources in a cost-effective manner.[120] In the western United States, the U.S. Department of Energy (DOE) and the Western Governors' Association (WGA) are leading the Western Renewable Energy Zone (WREZ) transmission planning process so that the Western Electricity Coordinating Council (WECC) can better identify and plan for renewable-energy-related transmission needs.[121] In addition, WECC's Transmission Expansion Policy Planning Committee (TEPPC) has aided regional planning by performing economic analyses and guiding transmission planning processes in the western United States. Several states (e.g., Wyoming and Kansas) are also addressing "across the seams" planning and cost allocation efforts by creating transmission authorities to stimulate the construction of high-voltage transmission lines.[122]

Some states have also succeeded in the implementation of energy policies supporting construction of transmission infrastructure. A good example is the Competitive Renewable Energy Zone (CREZ) initiative within the Electric Reliability Council of Texas (ERCOT). While it should be noted that ERCOT is unique in that it is a separate interconnection entirely within one state (none of the other contiguous 48 states are similarly situated), the CREZ effort represents the effectiveness of interconnection-wide planning for the development of interstate extra-high-voltage (EHV) transmission (at voltages 345 kilovolts [kV] and above).

Climate Change's Uncertain Impact on Transmission Planning

Government's response to climate change will further confound transmission planning and the estimation of future needs. Compliance with applicable RPS, the trend toward electrified transportation, and overall pressure on industrial sectors to reduce GHG emissions could result in tremendous additional demand on existing transmission infrastructure. Areas with high-quality renewable energy resources, such as wind power, solar power, and geothermal energy, tend to be located at significant distances from population centers. This fact is highlighted in DOE's *20% Wind Energy by 2030* report.[123] Accessing these resources and providing adequate capacity to facilitate new electrification initiatives in the transportation and industrial sectors will require expanded use of the transmission grid. Government at various levels, many utilities, and nongovernmental organizations

[119] Midwest ISO and others, "Joint Coordinated System Planning," collaboration to meet the requirements of the Joint Operating Agreements with the Midwest ISO, http://www.jcspstudy.org.
[120] Midwestern Governors Association, "MGA Energy Initiatives," http://www.midwesterngovernors.org/EnergyInitiatives.htm (accessed November 12, 2008); Office of the Governor & Lt. Governor of Iowa, "Five Midwestern States Announce Transmission Planning Initiative," September 18, 2008, http://www.governor.iowa.gov/news/2008/09/18_2.php (accessed November 12, 2008).
[121] Western Governors' Association, "Western Renewable Energy Zones," http://www.westgov.org/wga/initiatives/wrez/index.htm.
[122] Wyoming Infrastructure Authority, "Wyoming Infrastructure Authority," http://www.wyia.org; Kansas Electric Transmission Authority, "Kansas Electric Transmission Society," http://www.kansas.gov/keta.
[123] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* (Washington, DC: U.S. Department of Energy, 2008), http://www.20percentwind.org/20percent_wind_energy_report_revOct08.pdf.

are also working to develop and deploy Smart Grid options. These and other demand-side and distributed generation options will help offset a portion of the growing electricity demand and further reduce GHG emissions, but they will not obviate the need for significant new transmission.

Grid Congestion

The U.S. electric grid is highly congested in some areas, as DOE has noted in its 2006 *National Electric Transmission Congestion Study*.[124] New products and services could allow for more efficient use of existing transmission infrastructure. Because the location of transmission congestion changes depending on outage conditions, seasonal variation, and other factors, opportunities exist for transmission consumers to use spare transmission capacity during uncongested periods. Recent FERC rules put in place conditional firm transmission and generation re-dispatch services to address unanticipated transmission constraints. However, these new products and services cannot alleviate the need for transmission expansion.

The Rise of Smart Grid and Increasing Use of Plug-In Vehicles

Implementation of Smart Grid concepts will change the grid by enabling demand response / load management and other resources to be dispatched as generators are dispatched today. Plug-in hybrid electric vehicles (PHEVs) attached to the grid using Smart Grid technology also have significant potential to provide demand-side flexibility in the future, although the penetration of PHEVs would also increase overall electric load. Other energy storage technologies may also become cost-effective sources of system flexibility in the future. The interaction of these technologies with the transmission system, and the role transmission can play in better leveraging such technologies, will be an important component in the development of future plans.[125]

[124] U.S. Department of Energy, *National Electric Transmission Congestion Study* (Washington, DC: U.S. Department of Energy, 2006), www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf.

[125] See a detailed discussion of grid impacts of energy storage technologies and PHEVs in the EAC report, *Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid*, December 2008.

Increasing Investor Interest in Transmission Projects

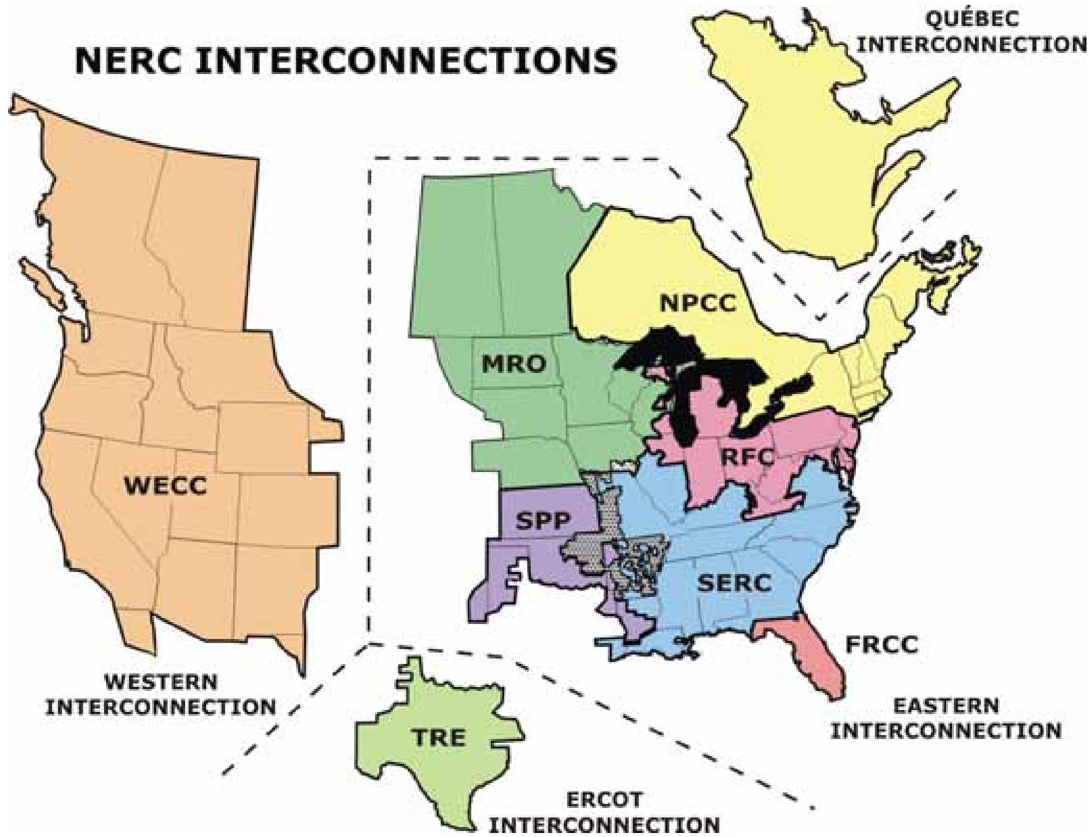
Perhaps more so than at any point in the electric industry's history, new entrants stand poised to have a significant impact on the nation's transmission infrastructure. While there have been fewer than a dozen new regulated utilities formed over the past 40 years, interest in the transmission sector is exceptionally high. Public power and rural electric cooperative utilities that use the transmission systems of neighboring utilities to move power supplies to their retail consumers are increasingly expressing interest in transmission ownership. In addition, a number of companies are exploring opportunities in the merchant transmission business. Most of these potential new entrants are drawn to the electric delivery business because of the obvious need for capital and the fact that a "21st century grid" will require new thinking, new technologies, and new business approaches, which help level the playing field with traditional utilities and provide multiple opportunities for growth.

In recent years, tens of billions of dollars of equity have been raised by infrastructure funds looking for opportunities to deploy their capital in regulated or unregulated projects. These new players have lower return expectations than traditional private equity funds, and their time frames for holding investments may be longer. In addition, commercial and investment banks have favored lending to utility projects, as they provide greater cash flow certainty during a period of economic unease. While these dynamics have changed as a result of the recent global financial downturn, it will be important to find ways of involving these new potential investors in developing solutions to enable meaningful investment in expanding and upgrading our transmission infrastructure.

Rising Global Demand for Equipment and Labor

The development of a more robust electricity transmission grid will certainly require more equipment, material, and labor resources at a time when there is a growing global demand limiting supply. Current financial conditions may ease the availability of these resources in the short term, as limited access to capital and the high cost of capital may delay transmission plans somewhat. However, as financial conditions ease, capital will likely be

Figure 3-1. Map of NERC Reliability Regions within the Four North American Interconnections



Source: North American Electric Reliability Corporation 2007.[126]

attracted to transmission investment again, driven by national imperatives to connect low-carbon resources to the grid. While global market forces may create better supply in the long term, the availability of equipment, material, and labor may be limited and more expensive in the mid term.

3.2 Barriers

The greatest barriers to transmission development have been: 1) planning (i.e., what project); 2) siting/permitting (i.e., whose backyard); and 3) cost allocation / time recovery (i.e., who pays).

Inadequate Interregional and Long-Term Transmission Planning

Currently, interregional planning within the eastern and western U.S. interconnections is inadequate, but it can be improved. (See Figure 3-1 for a map of NERC reliability regions and the four North American interconnections.) For example, the "lake effect" phenomenon, a power flow problem around the eastern Great Lakes, particularly Lake Erie, has existed for decades. This phenomenon, which has yet to be resolved, may have been a contributor to the spreading of the 2003 blackout in the eastern United States. Although system controls, procedures, and compliance with mandatory reliability standards were put in place to mitigate the circulating power flows, relatively little coordinated transmission investment has been made. The area surrounding Lake Erie comprises three RTOs in the United States and an independent system operator (ISO) in Ontario, Canada. RTOs (and ISOs) are responsible for transmission planning within their respective footprints, but they are not adequately addressing transmission planning challenges jointly with neighboring regions.

Coordinating transmission projects across the seams between RTOs and utility control areas is increasingly important to bring renewable energy to consumer loads, as well as to improve overall grid robustness and the acquisition of lower cost electricity. Often, however, there is no mechanism

[126] North American Electric Reliability Corporation, "Regional Entities, NERC Interconnections" http://www.nerc.com/page.php?cid=1%7C9%7C119 (accessed November 2008).

for approval, cost allocation, and/or selection of owners for projects that cross these seams.

Lack of Unified Structure to Support Efficient Permitting of EHV Transmission Lines

The permitting of transmission facilities is highly fragmented by the federal government, states, and local authorities. These fragmented processes were not established to develop interstate EHV transmission lines or facilitate access to remote renewable energy resources, nor do they provide proper consideration for crossing federal lands. Currently, local, state, and federal agencies are responsible for siting and permitting transmission lines in their respective jurisdictions. The siting of EHV transmission projects often involves multiple entities with varied processes.

Even relatively short transmission lines frequently require permits from various federal agencies that control the crossing of parks, agricultural lands, and rivers. Examples include the United States Fish and Wildlife Service (USFWS) and the Bureau of Land Management (BLM). In the western United States, almost all significant transmission projects require federal land or resource agency permits. While it should be noted that the western states and the affected federal land management agencies agreed to a regional transmission siting protocol in 2003 that handles multi-state transmission projects,[127] this protocol has not yet been tested on an actual project. Recent experience in California suggests that the federal permit process can be extremely cumbersome and time consuming, even for the construction of transmission to access renewable energy resources.[128]

Each local, state, and federal agency typically has its own permitting rules and processes, which are rarely consistent with each other. In addition, each agency also views the costs, benefits, and environmental impacts of transmission differently. Layered on top of these permitting arrangements may be RTOs that have planning and scheduling authority in some, but not all, parts of the country. In addition, NERC and its regional entities enforce compliance with reliability standards that affect transmission operations and development. The uncoordinated participation of this wide spectrum of interested parties, and the nature of interstate EHV transmission crossing jurisdictional boundaries, complicates and impedes the planning, approval, and permitting processes. This can further delay the already lengthy siting process, add to the cost of transmission projects, and increase the financial risk to a transmission developer.

A “poster child” example of this problem is American Electric Power's Jacksons Ferry, Wyoming, 765 kV transmission line. It required 16 years to complete, and nearly 14 of those years and $50 million was spent on siting activities. A portion of the siting problems that plagued the project was simply the mismatch between an interstate project and the non-integrated permitting processes of Virginia, West Virginia, and several federal agencies. Each set of rules and regulations was reasonable on its own, but when the project was revised to comply with requirements in one jurisdiction, filings needed to be amended in each of the other jurisdictions, extending the review time. This mode of permitting proved time consuming, inefficient, and costly for consumers.

The Energy Policy Act of 2005 (EPAct 2005) recognized the impediments to interstate transmission development and sought to address them in two ways. First, it provided for FERC “backstop” siting authority within National Interest Electric Transmission Corridors (NIETCs). These have proven to be controversial, both too broad in the view of some and too narrow in the view of others. Because NIETCs are based solely on congestion, the current designated corridors are limited in scope and do not take into consideration other needs such as access to renewable resources. Second, EPAct 2005 called for DOE to act as the lead agency for coordinating federal authorizations and environmental reviews for transmission. More than three years later, DOE has published a proposed

[127] Western Governors’ Association and others, “Protocol Among the Members of the Western Governors’ Association, The U.S. Department of the Interior, The U.S. Department of Agriculture, The U.S. Department of Energy, and the Council on Environmental Quality Governing the Siting and Permitting of Interstate Electric Transmission Lines in the Western United States,” http://energy.state.nv.us/2005%20Report/2005%20Appendices/App%20VIII/9-5wtp.pdf.

[128] Southern California Edison Company, “Comments of Southern California Edison Company” (Washington DC: U.S. Department of Energy, October 2008), http://www.oe.energy.gov/DocumentsandMedia/Southern_California_Edison_Co_Comments_on_DOE_Lead_Agency_Authority_RIN_1901_AB_18_10.20.2008.pdf.

rulemaking regarding its lead agency designation, but DOE as structured and with current resources is not well positioned to carry out the coordination duties pursuant to section 216(h) of the Federal Power Act. DOE should allocate proper focus and resources to this task, or this responsibility should be transferred to FERC, which has greater siting and National Environmental Policy Act (NEPA) expertise.

Lack of Clear Cost Allocation Policies

The difficulty in determining who should pay for transmission that benefits many users across multiple jurisdictions, for a variety of purposes and over a long time, is a serious obstacle to transmission development. As Nicholas Brown, President and Chief Executive Officer of Southwest Power Pool (SPP) said, "our industry desperately needs national leadership on allocating costs for the expansion of the bulk transmission system. We have planned regionally and interregionally for over a decade, but ideas remain on paper due to lack of needed cost allocation."[129] FERC has approved unique regional cost allocation approaches where RTOs have authority. In other regions, the task of cost allocation is delegated to individual states or utilities. In these areas, the lack of approved region-wide cost allocation methodologies and agreements can complicate and delay the planning and approval of interstate projects, thus at times creating a higher level of uncertainty and risk for investors. Moreover, a lack of cost allocation mechanisms can complicate projects that span multiple RTOs or RTO and non-RTO regions. Cost allocation policy can determine whether a project moves forward, especially because the construction of large-scale projects can extend over a number of years and require a large capital investment.

EHV transmission projects involve the large-scale transport of electricity, usually across long distances. Higher voltage increases the transmission efficiency and decreases the amount of electricity otherwise lost. Thus, the nature of EHV transmission generally means that its benefits are provided across wide areas, possibly spanning jurisdictional boundaries. For these types of projects, it is difficult to determine particular beneficiaries over the life of the projects. In addition, benefits are often categorized into "reliability" or "economic" benefits, and the allocation methodologies frequently differ between these categories. However, interstate transmission projects generally serve multiple purposes, with benefits that can vary over time and with changing system conditions. Attempting to assign costs for these types of projects to any particular group is often met with resistance from the group, causing delays. By contrast, in some jurisdictions transmission costs are shared across all load-serving entities in the footprint based on load ratio. In this way, major EHV infrastructure projects can be planned based on the needs of the entire region. This promotes projects that are designed to deliver maximum benefits to multiple stakeholders, minimizes the cost impact to any individual consumer group, and avoids disagreements that occur under "beneficiary pays" or "participant funding" approaches.

Without clear cost allocation policies, developing large-scale transmission projects is virtually impossible. In cases in which a potential transmission line crosses dissimilar cost allocation areas or RTOs, the project may be delayed to reconcile the cost allocation methodologies and determine who pays. Cost allocation disagreements can also impact transmission siting; therefore, resolution of these two issues must be linked. Indeed, EAC members believe that cost allocation is the single largest impediment to any transmission development, especially across multiple RTOs or across RTO and non-RTO regions. Reinforcing and clarifying FERC's ability to determine cost allocation methodologies could be an important step forward in expediting these processes and enabling investment to take place.

Uncertainty Regarding Cost Recovery From Retail Consumers for Transmission Projects

In addition to cost allocation, uncertainty with respect to cost recovery has a profound effect on decisions to build large-scale EHV transmission. The timely recovery of transmission investment is a vital component in attracting sufficient investment, particularly for projects with timelines that extend across many years. Since FERC issued its transmission incentive rule (Order No. 679), a number of transmission projects have been

[129] North American Electric Reliability Corporation, *Special Report: Electric Industry Concerns on the Reliability Impacts of Climate Change Initiatives* (Princeton, NJ: North American Electric Reliability Corporation, November 2008), 17, http://www.nerc.com/files/2008-Climate-Initiatives-Report.pdf.

proposed. However, for most transmission builders (builders other than independent transmission companies, whose rates are entirely FERC regulated), recovery of FERC-approved transmission costs must be approved at the state level, potentially resulting in "trapped costs."

State utility regulators representing retail consumers want to ensure that transmission projects approved on economic grounds do not result in costs that exceed the benefits. Further, they seek to avoid the use of financial incentives that encourage utilities to propose "unnecessary" infrastructure investments to increase their rate bases, or transmission projects that are more expensive than alternatives. Thus, some state regulators and consumers remain concerned about the costs of many proposed large-scale transmission projects and whether the cost of installed transmission projects may exceed their original estimates.

Formula rates and "pass-through" rates (state-approved mechanisms to allow for automatic recovery of FERC-approved investments) help provide the certainty needed to stimulate major transmission investment. However, the reconciliation of federal and state cost-recovery mechanisms to address both developer and consumer concerns is necessary to encourage the construction of the transmission grid that is required to achieve the nation's goals of energy security, electricity adequacy, and environmental protection.

A Growing Need to Optimize Grid Operation for Renewable Energy Resources

Optimization of renewable energy resources in concert with the operation of the grid is needed. Historically, the dispatching of resources depended on demand and the cost effectiveness of nearby generating plants. Today, congestion, weather (for renewable energy), and other factors often affect the dispatching of resources. Much higher renewable resource penetration will require an efficient and responsive fleet of traditional resources, new energy storage devices, and demand response / load management resources to fill the gaps created by the inherent variability of renewable energy resources. Potential operating restrictions related to air and water quality may impact the ability of existing traditional generation sources to help integrate renewable energy and could lead to complex operational issues. In addition, the growing complexities and more intensive use of the grid, the long distances to renewable energy resources, and the continued addition of air conditioning, power electronics, and computers will make control of the grid even more challenging for its operators.

Inadequate Grid Controls and Communication Systems

Better wide-area monitoring and controls are needed for proper protection and efficient operation of the transmission system. Much of the grid's existing capability is the result of well-engineered controls and communication systems. Without them, the ability of the grid to reliably transfer significant amounts of power would be greatly diminished. However, NERC has determined that mis-operation of protection devices and controls is causing a growing percentage of bulk transmission outages.[130] More sophisticated detection and control capabilities are needed and could be achieved with Smart Grid initiatives. This includes situational awareness tools for system operators to allow them to identify and implement timely control actions or to enable automatic control actions.

Limited Development and Deployment of New Technologies

There is a tremendous need for leadership in the area of research and development (R&D). The electric power industry is highly fragmented, and R&D expenditures total less than 1% of revenues.

The costs and risks to develop and implement a new technology can be substantial. FERC has encouraged development of advanced technology through incentives under EPAct 2005 to recognize these risks and reward "first adopters." However, more can be done to encourage the development of potentially beneficial technology and ensure recovery of investments in innovation. In particular, there is a need to ensure recovery of investments in promising technologies in situations where the benefits might not be seen for several years.

[130] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), http://www.nerc.com/files/LTRA2008.pdf.

Resistance to Entry of New Companies

New entrants and new investors stand poised to enter the transmission industry. While many observers view this interest as proof that new companies and new capital will flow into the electric power industry over the coming years, the reality is much less certain, as there are actually very few success stories. In some instances, the potential new entrant has proposed an uneconomic or unnecessary project, or made other mistakes, sometimes based on lack of experience. In others, utilities have fought bitter political battles at the state level to stop new entrants, or regulatory reviews have stymied projects.

Today, many incumbent electric utilities have a legal right of first refusal to construct, or arrange for construction of, any transmission project within their service territory. Reliability projects are generally completed expeditiously because improvements are required to meet NERC reliability standards. By contrast, transmission-dependent utilities (TDUs) and consumer advocates frequently express concerns that incumbent utilities can continue to exercise transmission and/or generation market power by delaying "economic" projects by requesting repeated feasibility and cost-benefit studies and using other delaying tactics. Some TDUs have also expressed interest in participating jointly with incumbent utilities and other transmission owners in new transmission projects or significant upgrades, contributing their own capital, but those expressions of interest have not been reciprocated in many cases.

3.3 Key Considerations

Perhaps the most important consideration for the development of the grid is our nation's developing vision for addressing climate change. Transmission can enable our electricity future by removing barriers for low-carbon resources and improving the delivery efficiency and effectiveness of the grid.

Addressing Climate Change

Transmission planning and development must be done in the context of comprehensive demand and resource analysis to ensure that demand-side resources and environmentally desirable supply-side resource options (such as Smart Grid options at the consumer and distribution level) are fully considered and pursued. Such planning must also account for the likelihood of further demand growth caused by increased electrification of the transportation sector and industrial processes as the United States pursues strategies to reduce society's impact on climate and the environment overall. The nation needs a broad vision for a transmission system that supports a national energy policy to meet the goals of energy security, electricity adequacy, and environmental protection. Collaboration among the many various stakeholders will be necessary to make this vision a reality.

Broadened planning efforts should allow for consideration of new technologies that maximize both cost benefits and system efficiencies while minimizing environmental impacts. For example, where appropriate and cost justified, such efforts may encourage greater use of higher voltage or EHV transmission lines, including complementary high-voltage direct current (HVDC) connections for transferring electricity from the nation's available sources of low-carbon energy to load centers, particularly where need for the lines is well established and corridors are limited or environmental impacts are a concern. These high-capacity lines enable the most prudent use of scarce corridors and can be effectively integrated to form a more efficient, expanded interstate transmission grid that will serve long-term needs.

Progressive planning efforts should also consider using advanced conductor materials and integrating more efficient equipment to minimize system losses and further reduce GHG emissions. Planning the transmission system of tomorrow is not only about building additional lines; it is also about designing a smarter, superior system. This approach may not be considered the least costly over short-time horizons, but it will provide significant benefits to consumers over longer periods going forward. To ensure lower prices and a higher-quality system for consumers, these broader planning efforts should consider environmental and cost-benefit analyses, including the effects of all cost-effective demand-side options, the deployment of a Smart Grid, and distributed generation systems.

Recognizing the Need for Longer-Term Planning for Transmission Infrastructure

Developing a robust electricity transmission network that enables the nation's electricity future requires longer-term regional (e.g., within or among neighboring states, RTO areas, or across multiple utilities) and interregional (e.g., within the eastern or western U.S. interconnections) planning. The exception is the ERCOT Interconnection, where interconnection-wide planning has been more progressive, facilitated by its single-state jurisdiction. Such planning must take into account not only traditional transmission planning issues—such as interconnection queues, estimating demand-side program impacts, regional seams issues, and "just-in-time" short-term transmission development—but also broader national goals.

Because the siting and construction of transmission infrastructure can take several years to complete, long-range planning must have the flexibility required to accommodate multiple scenarios. The full range of fuel sources, demand options, and transmission solutions must be thoroughly examined, and planning must occur with a greater geographic scope and longer time frame than ever before. Modeling the grid, particularly with respect to less-certain generation and load scenarios, needs to be enhanced. In many ways, adapting to today's energy landscape requires a fundamental shift in long-term and large-scale transmission system planning and construction. Regardless of geographic location, transmission must be viewed as a critical enabler of an adequate electricity future for the United States and planned with this in mind.

Supporting Effective Methods of Sharing Costs for Regional Transmission Projects

At the consumer level, sharing costs as broadly as possible reduces the rate impact while enabling the infrastructure that will reduce congestion and lower delivered energy costs. A study conducted by CRA International, for example, estimates that a $2.7 billion–$3.5 billion investment in the western portion of SPP for 1,200 miles of 765 kV transmission (the first two loops of the proposed SPP EHV Overlay) would result in an annual net benefit to the SPP region of $628 million–$728 million, not including the added benefits of economic development and reduced carbon dioxide (CO_2) emissions. This means that the cost of the added transmission would be fully offset within five years. This portion of the SPP EHV Overlay plan also enables the development of 14 gigawatts (GW) of wind power generation in the region. SPP's leadership and the CRA International study results demonstrate how regional transmission development can benefit the region with stabilized electricity costs and encourage renewable energy development.[131]

Ensuring Affordability for Consumers

Electricity must remain reasonably priced for consumers. Failure to keep electricity rates affordable will have a damaging impact on the nation's economy and the quality of life for many Americans. While transmission is only a small part of the average consumer's electricity bill today (typically less than 10%),[132] the construction of a major new line can cost more than $1 billion. The planned project must be assessed accordingly to ensure need, benefits, and minimal environmental impact. A properly planned, developed, and financed transmission system can facilitate lower overall costs for utilities, and ultimately for consumers, by creating better delivery efficiencies, greater market reach, and reduced market power for energy suppliers.

Advancing Automated Grid Control

Improved automated grid control can be achieved, in part, by accelerating the work under way to develop and deploy precise time-synchronized measurements on an interconnection-wide basis. This development effort is known as the North American SynchroPhasor Initiative (NASPI).[133] Time-synchronized phasor measurement units (PMUs) are often described as "diagnostic MRI (magnetic resonance imaging)" for the electric grid, providing continuous synchronized real-time data. The PMU concept should be further developed to provide automatic control of a modern grid by enabling the power system to adjust quickly to serious loss of transmission, generation, or load. As recommended in the final U.S.-Canada Power System Outage Task Force report on the 2003 blackout, such control

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[131] CRA International, "First Two Loops of SPP EHV Overlay Transmission Expansion: Analysis of Benefits and Costs" (CRA International, September 22, 2008), PowerPoint slides, http://www.spp.org/publications/ETA_OGE_WESTAR_Preliminary_Cost_Benefit_Analysis%20_from_CRA.pdf.

[132] Energy Information Administration, *Annual Energy Outlook 2008 with Projections to 2030* (Energy Information Administration, 2008), 131, http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf.

[133] Pacific Northwest National Laboratory, "North American SynchroPhasor Initiative," http://www.naspi.org (accessed November 12, 2008).

would improve the reliability of the grid and its capability to move power and could possibly prevent or mitigate the effects of a widespread blackout.[134]

Relieving Grid Congestion

Grid congestion increases costs to consumers and is a direct result of inadequate infrastructure to facilitate safe and reliable electricity deliveries. In addition to needed transmission expansion, technologies are available to improve utilization of existing infrastructure that may help reduce congestion and ensure reliable system operation.

It is possible to dynamically rate transmission lines for ambient weather conditions, which may allow more electricity to be transmitted over lines when air temperatures are lower than more conservative assumptions typically used for line rating. However, this will require transmission operators to know more about the system in near real time than is generally the case today. Making such options available to transmission operators, including variable-output renewable energy generation sources, can allow more efficient use of the existing infrastructure, more accurately calculate available transmission capacity, and significantly reduce the cost of reliably integrating new generation into the grid.

New devices can also help to enhance the controllability of the grid. For example, flexible alternating current transmission systems (FACTS) can provide control and voltage support to improve grid reliability and throughput. In addition, the use of HVDC to complement the EHV alternating current (AC) network the United States has today can also help control the network, provide additional interregional connectivity to improve grid stability, and mitigate the spread of blackouts.

A number of operational actions were recommended in the final U.S.-Canada Power System Outage Task Force report on the 2003 blackout. These recommendations are at various stages of development, and DOE is encouraged to ensure that ongoing activities are carried out. In addition, operation of the grid both now and in the future requires strict compliance with mandatory standards established and enforced by FERC and NERC. In addition, making the grid "smarter" must recognize that the grid must remain secure in all aspects, including cyber security.

Enhancing Grid Reliability through Actual or Virtual Consolidation of Balancing Areas

To make better use of renewable energy and share other resources, including demand response / load management, a wider geographic scope for energy "balancing areas" may make it easier to operate the electric grid reliably. Widening the geographic scope could provide more opportunity for excess generation in one region to be offset by reduced generation in another region. However, the benefit of larger balancing areas is generally more pronounced for wind energy than for other renewable energy resources because total wind power output is less variable over larger geographic regions and more resources are available to respond to this variability. More flexible dispatch, shorter-term dispatch schedules (reduced to five- or ten-minute intervals), better energy storage capability, and demand response / load management over larger geographic regions may enable the reliable integration of even more renewable energy generation and reduce the need for additional capacity. Solutions can take many forms, including consolidation of existing balancing areas into larger ones, as is the case in some RTOs, or "virtual" consolidation through coordination agreements. Nevertheless, these solutions remain dependent upon interstate transmission as well.

Cost responsibilities must be equitable and fair for operational and reliability impacts from any generation of any type, including wind power, being added to a balancing area. In addition, the balancing authority must be able to maintain compliance with NERC reliability standards after a generator has been added. DOE should consider recommendations from current efforts to mitigate the variability of wind power, including the NERC Planning Committee's Integration of Variable Generation Task Force Study and Electric Power Research Institute (EPRI) studies of variable resource (e.g., wind power) integration.

[134] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (North American Electric Reliability Corporation, April 2004) http://www.iwar.org.uk/cip/resources/blackout-03/.

3.4 RECOMMENDATIONS TO DOE

State, regional, and national priorities, including grid reliability, economic energy supply, energy security, and climate change can all be addressed through the development of a robust transmission system. The benefits of a robust grid include:

- Access to new generation technologies and the ability to share the benefits of demand response / load management and Smart Grid initiatives across broad regions
- Improved system resource adequacy, by allowing greater sharing of resources and less dependence on local generation and constrained fuel supplies
- Enhanced system reliability, security, and efficiency
- Increased market competition that will benefit consumers by eliminating grid bottlenecks, which inflate costs by restricting supply
- Lower or more stable rates for consumers over the long term through increased access to lower-cost resources and a more diverse portfolio of energy sources
- Access to renewable energy and other low-carbon resources to meet renewable portfolio standard requirements and GHG emission reduction goals
- Enabling the realization of environmental policy objectives

To achieve these benefits and support future electricity delivery, the EAC recommends that DOE pursue the following:

1. Lead comprehensive, long-term, interconnection-wide EHV transmission planning efforts by convening RTOs, state utility commissions, regional planning councils, and other stakeholders. These efforts should be expeditious and examine the costs, benefits, and environmental impacts of transmission plans to address reliability and economics with the full range of demand- and supply-side options, including the interconnection and integration of low-carbon resources.

DOE must support the establishment of long-term interconnection-wide planning efforts and models with broad stakeholder participation.

However, this “top-down” approach must be paired with a “bottom-up” approach that takes into account local needs and issues. DOE must link local, state, and regional efforts with national priorities to ensure a robust transmission system that provides large fractions of the population with increased access to the energy sources they need, including renewable energy resources. As stated in the conclusion of the Electricity Advisory Board’s 2002 *Transmission Grid Solutions Report*, “The importance of working cooperatively on the federal and state level to improve our transmission infrastructure cannot be overstated.”[135]

Key activities by DOE should include the following:

- Establish eastern and western interconnection-wide collaborative planning efforts that mitigate seams issues and incorporate broad stakeholder participation. These comprehensive planning studies, encompassing each of the eastern and western U.S. interconnections, should be undertaken to develop high-level EHV transmission plans. These studies, tailored to each interconnection while supporting common national goals, will serve to provide consistency and harmonization among regional plans. These

[135] Electricity Advisory Board, *Transmission Grid Solutions Report* (Washington DC: U.S. Department of Energy, September 2002).

efforts should include broad cost-benefit analyses to support the interconnection-wide transmission plans, and should be integrated with DOE's national transmission congestion studies.

- Identify "best practices" that encompass demand- and supply-side options, "technology-neutral" analyses, adequate assessment of environmental impacts (including GHG emissions), full support for the development of renewable and other preferred technology generation, robust planning horizons, and full consideration of the electrification of transportation elements and industrial processes for the nation's energy future. Widely distribute such "best practices" information to planning entities and governmental authorities.

2. Improve the process of siting transmission facilities. DOE should take a strong lead federal role for expeditious siting of transmission over federal land. Other ways to strengthen siting include: federal siting authority for EHV transmission above 345 kV; or supporting adoption of state, local, and federal "best practices," supporting coordination of multi-agency permitting activities, and expanding NIETCs with FERC backstop siting authority to address reliability, as well as interconnection and integration of low-carbon resources.

While opinions of the current siting processes and recommended courses of action vary, the EAC agrees that the status quo for transmission siting is unacceptable. The EAC also agrees that DOE must take a strong lead federal role for expeditious siting of all transmission over federal lands, allocating proper focus and resources to this task or delegating this responsibility to FERC.

Some members of the Committee advocate that DOE support FERC siting authority for transmission projects above 345 kV that address national priorities such as bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources as recommended through regional and interconnection-wide planning efforts. In addition, federal intervention may be needed for transmission facilities at 345 kV and below that support these national priorities.

However, urging passage of new legislation to provide for federal siting for all new EHV lines is not a unanimous recommendation of the EAC. Some EAC members do not recommend urging the Secretary of Energy to focus on passing new federal legislation that broadly preempts existing transmission siting laws in the absence of a federal energy policy and national renewable standard. These EAC members recommend increased multi-state collaboration and adoption of state, local, and federal "best practices." Other EAC members assert that NIETCs with FERC backstop siting authority should expand beyond congestion to address reliability as well as interconnection and integration of low-carbon resources. Still other EAC members contend that all transmission siting should be under FERC jurisdiction, similar to the rules and processes for interstate natural gas pipelines.

The key driver of policies in this area and others will be the development of a comprehensive national energy policy for the nation's electricity future. DOE should improve the process of siting transmission facilities as follows:

- Address siting issues by taking a strong lead federal role for expeditious siting of all transmission over federal land or delegate this responsibility to FERC.

Other alternatives to strengthen siting include:

- Support FERC siting authority for transmission above 345 kV as recommended through regional and interconnection-wide planning efforts that address national priorities such as bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources. Consider possible federal intervention for transmission facilities 345 kV and below that are needed to support these national priorities.
- Support adoption of state, local, and federal siting process "best practices," support coordination of multi-agency permitting activities, and expand NIETCs with FERC backstop siting authority to address reliability as well as interconnection and integration of low-

carbon resources (in addition to addressing congestion included in current rules).

3. Advise FERC to lead the development of broad cost allocation principles for EHV transmission. In addition, advise FERC to continue the use of formula rates for transmission recovery and encourage "pass-through" transmission rates to retail levels.

Broad cost allocation for EHV transmission facilities approved by regional and interconnection-wide planning processes must be developed and applied in a predictable fashion. Lack of predictable cost allocation impedes transmission investment, especially at the "seams" between two RTOs or other areas with dissimilar cost allocation practices. DOE should do the following:

- Advise FERC to provide leadership and use its authority to develop broad cost allocation methodologies for EHV transmission facilities approved by regional and interconnection-wide planning authorities. If FERC's authority on this matter requires clarification, pursue legislation to provide that clarification.
- Advise FERC to continue the use of formula rates for transmission recovery and encourage "pass-through" transmission rates (state-approved mechanisms to allow for automatic recovery of FERC-approved investments) to retail levels.

4. Enhance grid operations and control by expanding research and exploring new technologies, encouraging coordination/consolidation of balancing areas where deemed economical and reliable, and ensuring the implementation of ongoing recommendations from the U.S.-Canada Power System Outage Task Force report on the 2003 blackout.

The construction of a robust transmission network is a critical part of addressing the challenges of electric grid reliability, load growth, transmission congestion, access to lower-cost generation, and integration of renewable (and other low-carbon) generation. However, a number of steps can also be taken to operate the existing grid more efficiently, effectively, and reliably. While grid operation has a number of challenges, there are solutions available that should be developed in conjunction with transmission expansion. These solutions should include the following key DOE activities:

- Expand research into the following: (i) wide-area monitoring and control initiatives; (ii) network integration of renewable energy resources, including the development of tools to improve generation dispatch and system flexibility; and (iii) control center enhancements needed for grid security and the nation's energy future.
- Explore technologies that will improve the integration of variable renewable energy resources into the grid. Consider recommendations from NERC and EPRI efforts in this area. In addition, further investigate the benefits of Smart Grid technologies and demand response / load management while taking steps to ensure that the grid remains secure in all aspects, including cyber security.

- To improve the integration of variable renewable energy resources and further the benefits of Smart Grid technologies and demand response / load management, encourage coordination/consolidation of balancing areas when the benefits are shown to be greater than the costs, any operational and reliability cost impacts are equitably allocated, and NERC reliability standards are followed.
- Ensure the implementation of ongoing recommendations from the U.S.-Canada Power System Outage Task Force report on the 2003 blackout and direct actions if these recommendations are not successfully implemented. Integrate recommendations from the prior and forthcoming DOE transmission congestion studies into these efforts as well.

5. Lead technological innovation by providing additional funding and by engaging participants in joint efforts to develop and demonstrate new technologies. Advise FERC to support continued incentives and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.

In transmission, R&D efforts are needed in five broad areas: (i) achieving more effective use of existing rights-of-way; (ii) application of improved controls and diagnostics necessary for grid security and the nation's energy future; (iii) enhancing asset reliability and flexibility with lower lifetime costs; (iv) reducing environmental and climate change impacts; and (v) advancing Smart Grid concepts to facilitate a self-healing grid and demand response / load management options.

As aging transmission facilities are upgraded and replaced, and as new facilities are designed and built, pursuing the R&D efforts listed above will support the application of technology solutions that maximize the capability and reliability of the transmission network while minimizing investment in unnecessary infrastructure and reducing environmental impacts.

DOE can provide leadership in the introduction of novel technologies through collaboration with industry and entities such as EPRI. Elements of a futuristic grid have been articulated through various industry initiatives, including the DOE Smart Grid Task Force, EPRI IntelliGrid™ and National Energy Technology Laboratory Modern Grid Initiative. In addition, countries in Europe have successfully integrated more than 50 GW of wind power. Through the study of European experiences with wind power resources, DOE can facilitate the U.S. electric power industry's understanding of how to address the variability of wind power resources and the technical requirements for reliably interconnecting them to the grid. However, the current DOE Office of Electricity Delivery and Energy Reliability R&D budget is far lower than that of any other energy research area. An increase in R&D funding from DOE is needed to further grid modernization efforts. If the economy of the United States depends on the energy future of the United States, and a robust and technologically advanced interstate grid will enable that future, then funding levels need to support strong federal leadership. DOE should:

- Formulate an R&D roadmap, build an R&D portfolio, provide seed funding, and engage willing participants in joint efforts to develop and/or demonstrate new technologies.
- Increase federal funding for transmission R&D and provide leadership at the federal level. Increase participation by national laboratories.
- Advise FERC to support continued incentives for beneficial technology development and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.
- Collaborate with EPRI and other private and public organizations to leverage R&D resources.

6. Reduce barriers to financing and construction of transmission by supporting new transmission ownership structures and advising FERC to encourage expedited timeliness for construction of economic projects, provide opportunities for other industry participants, and encourage sound agreements for operations, maintenance, restoration, and reliability compliance where joint ownership is present.

While policymakers and utility executives must become more engaged in defining the nation's energy priorities, immediate benefits can accrue from a more robust high-voltage electric transmission system. Resolution of impediments to the construction and integration of such transmission infrastructures into the present and envisioned regional and national grids is imperative.

A broader universe of entities should be encouraged to invest in transmission facilities, through vehicles such as joint ownership. When ownership and investment is shared, risks associated with large capital investments are reduced. Such arrangements might also reduce difficulties in accessing capital for large transmission projects, which could well be adversely affected in the next few years by the current economic downturn. Facilitating investments in transmission projects by a variety of entities with different business models (i.e., publicly and cooperatively owned, as well as shareholder owned) can also dispel the public's concerns that utilities are proposing such major transmission additions solely or largely to increase their rate bases and enhance shareholder profits.[136]

While increased participation is encouraged, jointly owned transmission projects must be supported through agreements that address operation, maintenance, restoration, and compliance with reliability standards. Incumbent utilities should not be looked upon as operator, maintainer, and restorer of last resort and have reliability compliance responsibilities without compensation, unless they have agreed to be responsible for such activities.

In addition, FERC and RTOs should be encouraged to develop processes for dealing with "across the seams" projects and facilitate independent transmission company participation and utility partnerships in "bidding" for construction rights. Key DOE activities should include the following:

- Support reduced barriers for transmission investors and new transmission ownership structures while ensuring that reliability is not jeopardized (DOE and FERC).
- Advise FERC to encourage states and RTOs to develop expedited timelines whereby utilities must commit to either constructing (or contracting for the construction of) economic projects and provide opportunities for other industry participants interested in contributing capital investments.
- Advise FERC to encourage sound agreements for operations, maintenance, restoration, and reliability compliance where joint ownership is present.

[136] One example of such joint transmission development and ownership is the CapX 2020 project in the Upper Midwestern United States. See CapX 2020, "Delivering Electricity You Can Rely On," http://www.capx2020.com.

Chapter 4
Generation Adequacy

Trends in electricity use are always subject to change based on economic conditions, energy efficiency and demand response initiatives, and other variables. The *Wall Street Journal* recently highlighted a sudden drop in electricity consumption as the U.S. economy stalled temporarily in 2008.[137] However, the Electricity Advisory Committee (EAC or Committee) concludes that the case for significant generation additions is robust across all plausible demand scenarios, given the combined environmental and economic imperatives of meeting the nation's growing energy service needs while replacing an aging and inefficient fleet of power plants. U.S. coal generation alone totals more than 300,000 megawatts (MW), much of which predates the Johnson Administration.

During the late 1990s and early 2000s, overall baseload generation construction declined as generators were reluctant to commit resources to an unsettled regulatory and developing market-based environment. However, in that same time frame, non-dispatchable or variable land-based wind power and other renewable energy generation resources began to gain a foothold in the United States, where non-dispatchable resources have grown from a 2,113 MW capacity in 1990 to 16,114 MW in 2007.[138] Though geothermal generation has decreased by about 372 MW, solar power has increased by 184 MW and wind power by 13,817 MW in this same time frame.[139] A recent wind power report, prepared for the presidential transition team, calls for the availability of sufficient wind resources to meet 20% of the nation's energy requirements by 2030.[140] As a clean abundant resource, solar power has almost unlimited potential. These resources and other clean generation technologies have the potential to contribute substantially more to the nation's energy supply adequacy.

Encouraging and managing new generation technologies while removing barriers to their development will be crucial to the nation's generation adequacy. Doing so will require bold, decisive action from the U.S. Department of Energy (DOE) and the Obama Administration.

4.1 Trends and Drivers

Declining Growth in New Generation

Ten-year generation growth rates have actually declined from a maximum growth rate of 4.08% in the 1970s to 1.29% during the 2000–2007 time frame. The net summer capacity 10-year growth rates have declined from a maximum growth rate of 9.22% in the 1950s to 3% during 2000–2007 (see Figure 4-1).[141] Electricity generation growth rates have fallen significantly, but capacity growth rates have declined almost twice as much. Because so little new generation is being built, adequacy of supply is a concern.

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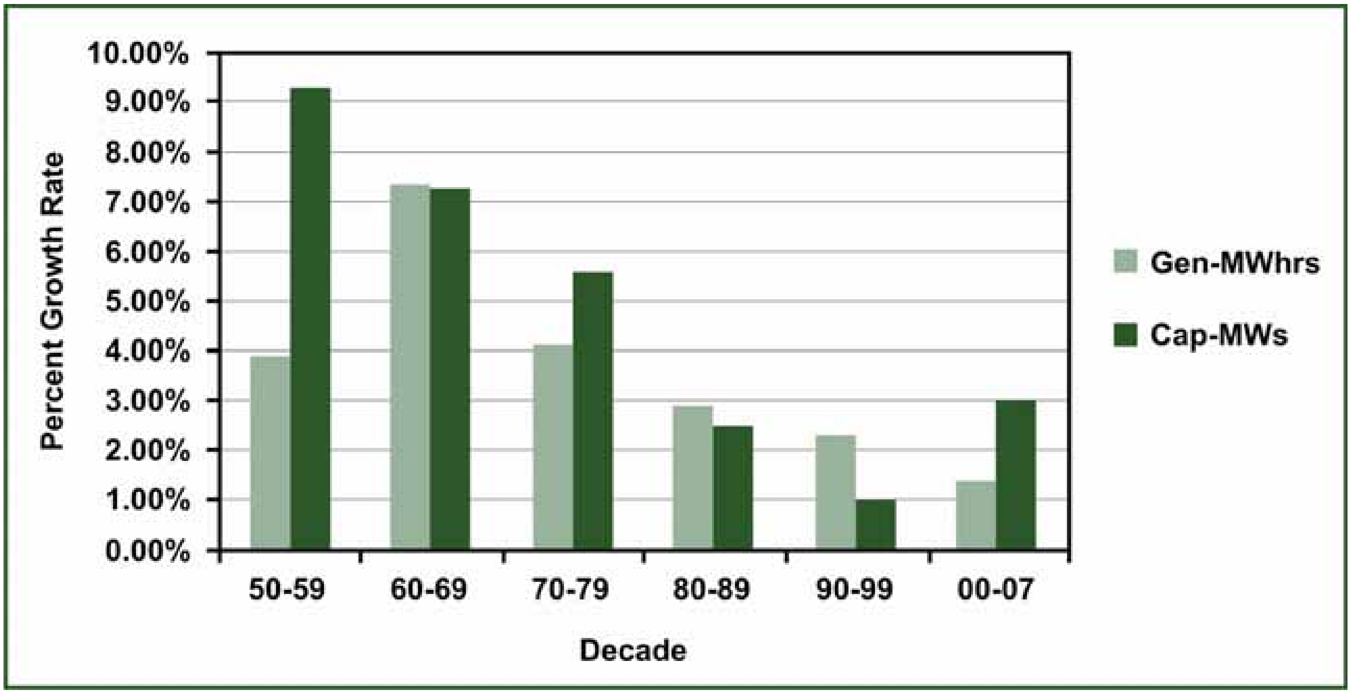
[137] Rebecca Smith, "Surprise Drop in Power Use Delivers Jolt to Utilities," *Wall Street Journal*, Nov. 21, 2008.
[138] Energy Information Administration, *Annual Energy Review* (Energy Information Administration, 2007), table 8.11a, http://www.eia.doe.gov/emeu/aer/elect.html.
[139] Ibid., table 8.11c.
[140] American Wind Energy Association, *Wind Energy for a New Era* (Washington, DC: American Wind Energy Association, November 2008), http://www.newwindagenda.org.
[141] Energy Information Administration, *Annual Energy Review* (Energy Information Administration, 2007), table 8.2a, http://www.eia.doe.gov/emeu/aer/elect.html; Ibid., table 8.11a; Ibid., table 8.11b.

Figure 4-1. Energy and Capacity Growth Rates



Source: Energy Information Administration 2007.[142]

Adequacy of Supply

The North American Electric Reliability Corporation (NERC) estimates a peak summer load growth of 16.6% over the next 10 years and notes in its *2008 Long-Term Reliability Assessment* (LTRA) report that some geographic areas face potentially inadequate generation-resource margins to meet growing peak load conditions in the near term. Though the 2007 LTRA report cited considerable concern over future inadequate reserve margins, new generation plans and a peak demand reduction of 1% from demand response / load management efforts have moderated those concerns in the 2008 LTRA report. It cites an approximate 4.2% improvement in reserve margin over the 2007 level; however potential resource concerns remain in the Southwest and western Canada.[143]

Forecasting capacity growth over the next 10 years is not an exact science. There may be some confidence in new capacity estimates in regulated state jurisdictions that require capacity planning, but in market-based regions, the forecast accuracy is severely limited. Regional transmission organizations (RTOs) may review and study all potential generation projects, but only a small percentage may actually be built and interconnected. Additionally, new gas plants can be constructed in shorter time frames, making it unlikely that future plans for these assets extend much beyond a three- to four-year time frame. A forecasted declining reserve margin may be more representative of past planning practices than a realistic picture of the future.

New generation is key to maintaining system reliability, and states play a major role in securing that new generation. In state-regulated environments, state public utilities commissions (PUCs) typically charge vertically integrated utilities with maintaining resource adequacy, and may approve cost recovery for generation to satisfy adequate reserve margins. States may impose capacity planning mandates on utilities and typically control the siting process. Some RTOs, recognizing the capacity shortages as reserve margins shrink, have introduced forward capacity markets to provide financial incentive for new capital investments.[144] These markets are intended to stimulate new generation and help maintain reserve

[142] Ibid., table 8.2a; Ibid., table 8.11a.
[143] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), 8–9, http://www.nerc.com/files/LTRA2008.pdf.

[144] Ibid., 10.

margins and adequate reliability, but they have not been shown to do so to date.

Aging Plants

The generation infrastructure in the United States is aging faster than it is being replaced. Although the recent construction of new gas-fired generation and renewable energy plants has helped to ease that concern, the United States continues to rely on generation capacity built in the 1960s and even the 1950s. As generation companies retire those older units, the development of new generation resources will be essential. In 1995, the average age of utility generation plants was approximately 40 years. Though that average has fallen to 37 years in 2007, new generation is still required to secure the nation's energy future.

Changing Portfolio Mix

The 2007 profile of generation capacity[145] has changed significantly from that of the 1990s. In 1990, 42.6% of generation capacity came from coal, 18.3% from natural gas, 14% from nuclear, and 10.8% from petroleum. By 2007, coal accounted for 31.9% of capacity, natural gas more than doubled to 39%, nuclear decreased to 10.3%, and petroleum decreased by nearly half to 5.9%. The recent construction of less capital-intensive and cleaner gas-fired generation plants has made natural gas the largest new source of generation capacity. During this time, renewable energy sources also increased their role in the capacity mix; though capacity from geothermal decreased slightly, biomass increased, solar increased slightly, and wind power grew by a factor greater than eight (see Figure 4-2).

More Costly Plants

New generation plants are considerably more expensive than their historical counterparts. Driven in part by increasing environmental requirements and rising resource prices, new plant costs have more than doubled in the past 10 years. Construction of a conventional natural gas combustion turbine plant costs about $150 million to $200 million—approximately $500,000 per megawatt generation capacity. In contrast, a combined cycle gas plant—the more common generation plant constructed today—costs about $700,000 per megawatt to build. At a 200–400 MW generating capacity, plant construction can total $200 million–$400 million. A new integrated gasification combined cycle (IGCC) plant with carbon sequestration could cost more than 3.5 times as much, or roughly $1.4 billion, a cost similar to offshore wind power costs.[146]

Cost of Fuels, Transport, and Storage

With the majority of energy still generated from baseload coal-fired plants, quality coal must continue to be available and affordable in the future. Newly constructed gas-fired generation capacity has similar concerns with natural gas supply. Though there were no significant fuel disruptions or related generation shortages in 2007, fuel supply has seen volatile periods in past years due to overwhelming storm damage, labor disputes, or storage/transportation issues. An adequate supply of fuel with appropriate reserves is essential to maintain a reliable energy supply in the future.

The Energy Information Administration's (EIA) *Annual Energy Outlook 2008* projects coal and natural gas prices to 2030. Considering slower economic growth and added environmental concerns, the report predicts coal production will range from stable to a 5% increase.[147] It predicts western mine-mouth coal prices will decrease by approximately 6% to $1.14 per million British thermal units (Btu) by 2020. However, coupled with higher mining labor and transportation costs, delivered coal prices are expected to remain relatively stable through 2030.

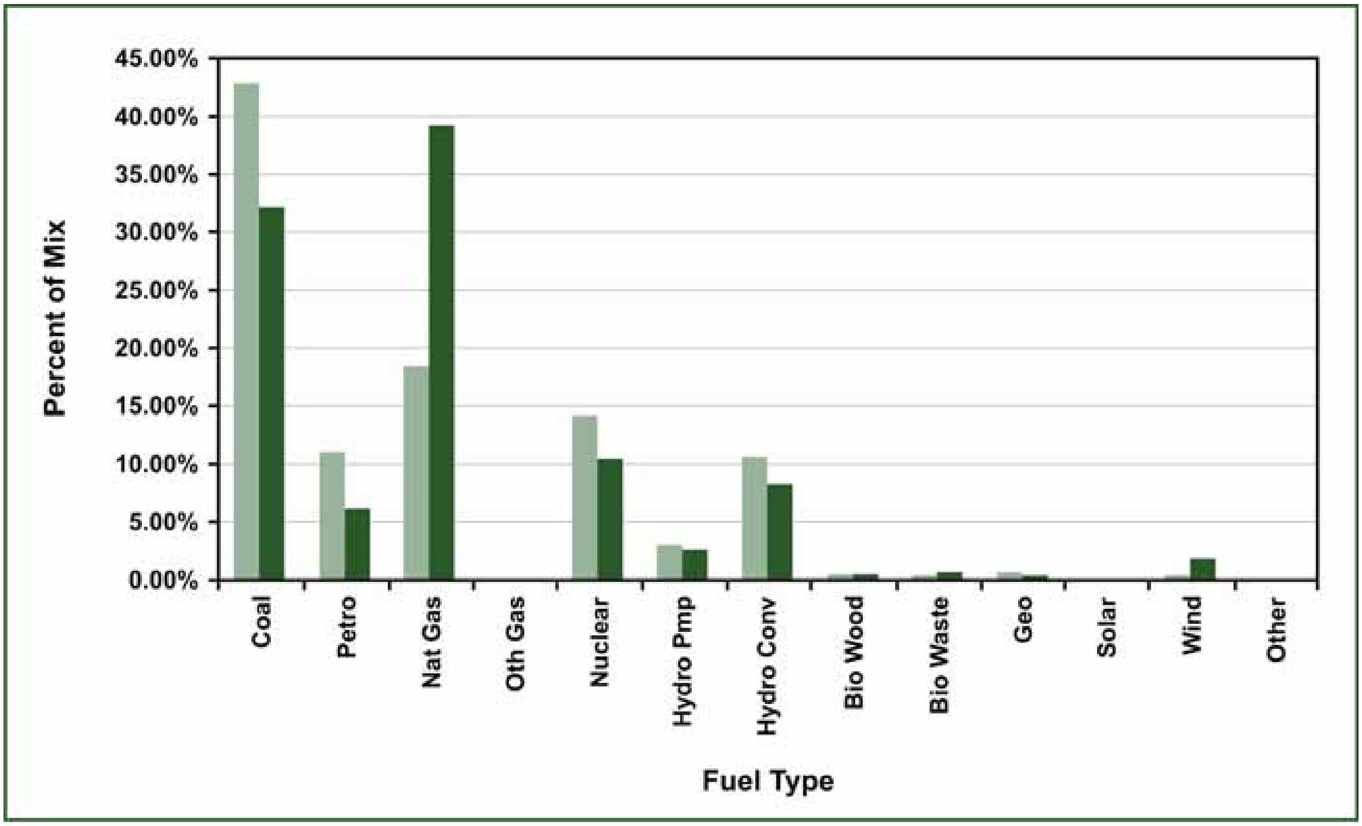
Natural gas supply and use in generation is much more cost dependent. Higher gas prices tend to stimulate production but curtail gas-fired generation, unless it is absolutely needed for reliability. Lower gas prices increase the use of gas in electric

[145] Energy Information Administration, "Generation Capacity," *Glossary*, http://www.eia.doe.gov/glossary/ glossary_g.htm. EIA defines generation capacity as "the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions." Capacity represents the level of generation output available from existing plants and is different than the actual energy generated by those plants. While natural gas may now be the largest capacity resource, it does not run as often as baseload coal or nuclear power plants, which currently provide the majority of megawatt-hour energy for consumers.

[146] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008* (Energy Information Administration, June 2008), table 38, http://www.eia.doe.gov/ oiaf/aeo/assumption/pdf/tbl38.pdf.

[147] Energy Information Administration, "Coal Forecast," *Annual Energy Outlook 2008 with Projections to 2030* (Energy Information Administration, 2008), http://www.eia.doe.gov/ oiaf/archive/aeo08/coal.html.

Figure 4-2. Capacity Mix Comparison, 1990–2007



Source: Energy Information Administration 2007.[148]

generation without stimulating new exploration and development. While most residential, commercial, and industrial consumers must rely on gas at market price for heating and process uses, electricity generation can rely on coal, nuclear, oil, and other substitutes when gas prices are high. The EIA predicts a gradual depletion of existing 48-state and shallow-water reserves, to be replaced by new, higher-cost Alaskan gas finds, deep-water finds, and unconventional production (e.g., coalbed methane, tight sandstones, and gas shales). At moderately higher prices and with declining domestic and Canadian production, liquefied natural gas (LNG) imports will continue to increase to meet domestic demand requirements. While the annual level of LNG imports may vary due to global market prices, EIA expects a continued gradual increase. Overall, domestic gas production is expected to grow modestly through 2030, dependent on market price variations and supplementation by LNG imports.[149]

Though the storage and transportation of fuels is currently adequate, it remains a key future concern in the fuel industry. With a growing reliance on LNG, it is unclear whether the United States has adequate storage facilities to match its need. Mid-winter deliveries are common in Europe, where there is also a heavy dependence on LNG and storage sites are limited. However, an extremely cold season could make mid-winter LNG deliveries unavailable to U.S. markets, exemplifying the need for adequate storage facilities.

While trucks deliver some coal to nearby power plants, the majority of U.S. coal makes its way from mine to market via rail car. Disruption of rail transport for rail line maintenance or train maintenance can have severe repercussions for the energy industry. In 2005, adverse weather and

[148] Energy Information Administration, *Annual Energy Review* (Energy Information Administration, 2007), table 8.2a, http://www.eia.doe.gov/emeu/aer/elect.html; Ibid., table 8.11a; Ibid., table 8.11b.

[149] Energy Information Administration, “Natural Gas Demand,” *Annual Energy Outlook 2008 with Projections to 2030* (Energy Information Administration, 2008), http://www.eia.doe.gov/oiaf/archive/aeo08/gas.html.

accumulated coal dust on track beds caused two derailments coming out of the Powder River Basin area, a major western supplier. Rail supply shortages can force users to deplete their own emergency stockpiles and require additional transport to re-establish them. Increased maintenance and diesel fuel costs have made rail transport more expensive. Rail carriers have expressed concern that consolidation savings are no longer available, and they may need to charge higher rates to fund continued growth of the rail infrastructure to meet increasing demand.[150]

Reliability and Cost Challenges for Renewable Energy Resources

The recent growth in wind power generation, while beneficial from a generation standpoint, has also created system planning challenges. Wind power and solar power, often referred to as variable resources, are not controllable as coal, nuclear, and gas-fired generation are. Just as the potential for baseload generation outages must be taken into consideration in system planning, so too does the availability of variable resources. When large areas of Texas, one of the largest wind power producing states, recently experienced high temperatures, low wind-power availability, and baseload generation outages, serious reliability and pricing issues arose. The lack of any generation during peak load periods forces dispatch of higher-cost generation. As renewable variable resources continue to grow in the capacity mix, reserve margins, particularly of controllable plants, become increasingly important.

Renewable energy resources continue to face price competition from baseload generation facilities. As high-voltage transmission grids expand and permit the efficient flow of energy from further distances, this competition is likely to rise. Renewable energy generators will need to find new ways to control costs in larger competitive markets. Technology advances and continued funding for energy research are essential to overcome reliability and cost challenges.

Combined Heat and Power Generation

Combined heat and power (CHP) systems, also known as co-generation, can play a key role in providing new cost-effective and efficient energy systems. While typical generation plants have relatively low efficiencies, CHP generates both electrical and thermal energy with resulting higher efficiencies. The thermal energy is typically used near the generation source, reducing environmental emissions and energy losses.

CHP installations increased significantly during the 1980s and early 1990s; CHP provided 10,000 MW of electric capacity in 1980, which increased to 44,000 MW by 1993.[151] Most of these facilities were installed at large industrial sites where there was also a need for thermal energy. Between 1990 and 2007, overall CHP thermal Btu output actually declined by approximately 4.2%.[152] However, for the electric power sector only, thermal Btu output has increased from 251,635 billion Btu in 1990 to 363,843 billion Btu in 2007, an increase of 44.6%.[153]

CHP can be an effective approach to improving energy efficiencies, particularly where there is a productive use of the thermal energy output. Using electricity for equipment needs and thermal energy for heating and cooling in close proximity to loads can offer significant efficiencies of operation and reduced environmental impact.

Distributed Generation

Distributed generation (DG) will play a growing role in providing generation adequacy in the future. While not necessarily competitive at today's costs for baseload generation, it does offer savings when used to reduce peak demands. The EIA forecasts almost 5,000 MW of this type of capacity by 2010,[154] with assumptions on reduced costs leading to continued growth in this sector of generation.

In addition, distributed generation can offer two large advantages over centralized baseload plants. Having multiple smaller generation units distributed throughout a system may enhance system security by making it more difficult to eliminate all generation

[150] Energy Information Administration, "Coal Transportation Issues," *Annual Energy Outlook 2007* (Energy Information Administration, 2007), http://www.eia.doe.gov/oiaf/aeo/otheranalysis/cti.html.

[151] R. Neal Elliott and Mark Spurr, "Combined Heat and Power: Capturing Wasted Energy," *American Council for an Energy-Efficient Economy*, May 1999, http://www.aceee.org/pubs/ie983.html.

[152] Energy Information Administration, *Annual Energy Review* (Energy Information Administration, 2007), table 8.3a, http://www.eia.doe.gov/emeu/aer/elect.html.

[153] Ibid., table 8.3b.

[154] Robert T. Eynon, "The Role of Distributed Generation in U.S. Energy Markets," *Energy Information Administration Forecasts* (Washington DC: Energy Information Administration), http://www.eia.doe.gov/oiaf/speeches/dist_generation.html.

sources. Second, generation added near the point of consumption offers improved reliability and decreased losses, while potentially freeing up additional line capacity, delaying new infrastructure investment, and helping hold down consumer delivery costs if properly sited, maintained, and coordinated with the utility or system operator. However, challenges remain to sort out what backup power requirements exist for those using distributed generation and how they can be most effectively integrated, while avoiding cross-subsidization issues with other consumer classes.

2010 Trends

If current trends continue, there is a consensus on the following:

- U.S. reserve margins will continue to decrease.
- Construction of renewable and distributed resources will continue accelerating.
- Reliability will become more heavily dependent on transmission infrastructure.
- Gas-fired generation will continue to dominate new power-plant growth.
- Nuclear or coal baseload generation, if constructed, will be a much more costly endeavor.

4.2 Barriers

Political, economic, and environmental regulations, as well as basic technological and physical restrictions, can each bar greater contributions of generation resources to the nation's energy supply. Detailed below, these barriers will be the foremost obstacles to adding new generation.

Achieving Economic Viability

Project developers must overcome four principal obstacles to make new generation economically viable.

Achieving Return Commensurate with Risk

The shift in the portfolio mix to cleaner, more costly fuels and more costly renewable energy generation, coupled with recent slower demand growth,[155] creates a new paradigm in both regulated and unregulated areas of the United States—one which favors short-term, low-cost, higher-return investments over high-cost, longer-term, lower-return investments. In dynamic, changing industries without long-term policy direction and commitment, investors, whether public or private, will tend to favor the short-term approach. However, the energy and operating costs, ultimately paid by consumers, may well be higher for low-cost plants and lower for high-cost plants, depending on fuel prices and dispatch times. The challenge in the generation industry is to attract the longer-term baseload commitments and insulate them as much as possible from changing federal policies to reduce investment risk and financial premiums.

Financial risk is a key barrier to new generation development. Both investors and generation companies aim to maximize return and minimize risk. In today's market, gas-fired facilities and wind power farms are lower-risk investments, particularly where the projects have a guaranteed sales contract or can receive regulated cost recovery. Gas-fired facilities are relatively inexpensive and quick to construct and have fewer environmental implications. Though wind power farms have higher capital costs, the fuel is guaranteed free for the life of the plant. These facilities, however, cannot supply baseload generation like new large-scale coal or nuclear generation facilities. Achieving economic viability for nuclear and coal plants will require a mechanism to reduce business risk factors and increase potential returns.

Overcoming the Boom/Bust Cycle

Developers invest in generation projects when prices are sufficiently high to provide an acceptable return. Boom/bust investment cycles occur when large generation projects introduce large blocks of capacity after lengthy lead times, satiating the market demand. Increasing shortfalls in generation follow, again raising capacity prices to acceptable investment levels. The quick construction time of smaller gas- or wind-powered projects allows them to take advantage of capacity shortages with higher return on investment. However, large baseload capacity projects are limited to those times when demand and prices are significantly higher, thus reinforcing the cyclic investment process. Making new projects economically viable during lower demand growth periods will require policies and actions designed to stabilize investment returns, capacity, and energy prices.

[155] Rebecca Smith, "Surprise Drop in Power Use Delivers Jolt to Utilities," *Wall Street Journal*, Nov. 21, 2008.

Reducing Risk by Long-Term Contracts

With rapidly changing markets and regulatory environments, purchasers and suppliers are both reluctant to enter into long-term agreements. Changes to the generation or transmission landscape, new environmental requirements, siting and development hurdles, regulatory review, and a myriad of other variables can reduce a contract to out-of-market pricing very quickly. However, for generation companies seeking external financing to build new capacity, long-term contracts are essential. In addition, long-term contracts can dampen the boom/bust cycle by creating more stable returns not subject to changing demand and supply pricing. Many generation projects require purchase-power agreements and policies that support the negotiation and adoption of long-term contracts.

Reducing Risk by Assuring Asset Cost Recovery

Whether in an organized market arena or vertically regulated jurisdiction, investors will not commit funds if their ability to recoup investment costs is uncertain. In organized markets, the generator typically recovers its costs through capacity and energy payments obtained from the RTO markets. However, even in recently created capacity markets, there are limits on the level and duration of payments. In regulated markets, cost recovery depends on the regulatory authority and the determination of how prudent the investment is. While less risky, the return on investment is also typically lower.

Generation companies are spending increasing amounts of time and resources to meet planning, permitting, siting, and interconnection requirements to build new generation, especially with new technologies. The recovery of significant development costs can be more problematic than the recovery of hard asset costs and subject to higher levels of scrutiny. To secure cost recovery for both hard asset and development costs, regulatory approaches and market rules that provide longer-term certainty are needed.

Political and Regulatory Uncertainty

Continued uncertainty in the energy sector about expected political or regulatory actions has slowed potential new generation projects. Federal legislators have been unable to produce a comprehensive energy plan or establish long-term energy policies. Production tax credits, investment tax credits, and grant programs have typically been renewed in short-term increments. The expectation of stricter federal regulations on carbon emissions or air quality has stalled generation projects. The challenge here is not building new generation, but establishing policies and regulations that will allow developers to predict the economic viability of generation projects. Three detailed examples of this uncertainty follow.

Grants and Tax Incentives

As part of the Energy Improvement and Extension Act of 2008, Congress extended the production tax credit (PTC) through 2009 for wind energy—originally set to expire December 31, 2008—to stimulate renewable energy generation. Established in 1992, the PTC has created uncertainty in the renewable energy industry since its first lapse for wind power generation in 1999, followed by additional lapses in 2001 and 2003. According to the American Wind Energy Association (AWEA), new installed wind power capacity declined by 93%, 73%, and 77% respectively during those years.[156]

Investment tax credits for renewable energy facilities were also scheduled to expire in December 2008 but were extended for eight years in the same legislation. This was critical for higher-cost renewable ventures such as solar power. However, Congress must begin thinking—and legislating—in terms of 20–30 years for generation resources.

Loan guarantees for energy projects are another federal policy plagued by uncertainty. The Energy Policy Act of 2005 authorized DOE to issue loan guarantees to eligible projects that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases and employ new or significantly improved technologies. However, annual Congressional funding approvals limit DOE's authority. In 2008, Congress authorized $38.5 billion in loan guarantee authority for innovative energy projects: $18.5 billion was allocated for nuclear power facilities; $2 billion for advanced nuclear facilities for the front end of the nuclear fuel cycle; $10 billion for renewable and/or energy-efficient systems and manufacturing, and distributed energy generation/transmission and distribution; $6 billion for coal-based power generation and industrial gasification at retrofitted and new facilities that incorporate carbon capture and sequestration or other beneficial uses of carbon; and $2 billion for advanced

[156] Anita Huslin, "Energy Boost," *Washington Post*, sec D-1, April 14, 2008.

coal gasification.[157] By October 2008, DOE had received 19 Part I applications from 17 electric power companies for federal loan guarantees to support the construction of 14 nuclear power plants in response to DOE's June 30, 2008, solicitation. The applications reflect the intentions of those companies to build 21 new reactors, with some applications covering two reactors at the same site. The nuclear industry is now asking for $122 billion in loan guarantees, significantly exceeding the $18.5 billion currently allocated.[158] The energy sector's dependence on Congressional funding thus introduces short-term uncertainty into long-term construction projects.

Climate and Environmental Issues

Potential carbon-reduction and climate-change mitigation regulations introduce numerous uncertainties for new generation. Ten northeastern and Mid-Atlantic states and several western states have already enacted mandatory carbon reduction plans. The northeast states' Regional Greenhouse Gas Initiative (RGGI) establishes a cap-and-trade program to reduce carbon emissions 10% by 2019. The price of carbon emissions, established in the September 25, 2008, RGGI auction, was $3.07 per ton.[159] The Western Climate Initiative (WCI), which includes seven western states and several Canadian provinces, aims to reduce carbon emissions 15% below 2005 levels by 2020 by employing a cap-and-trade program. There is no national regulation at the time of this report's publication, but the uncertainty of a federal program's size, goals, and implementation continues to affect the construction of carbon-emitting generation plants. Building any type of carbon-emitting plant today is difficult given the uncertainty of how much the plant and the electricity it generates may ultimately cost.

Along with carbon reductions, there is the potential for changing regulation on air pollutants, chiefly sulfur oxide (SO_x), nitrogen oxide (NO_x), and mercury, in the near future. On March 10, 2005, the Environmental Protection Agency (EPA) issued the Clean Air Interstate Rule (CAIR), designed to achieve the largest reduction in air pollution in more than a decade. CAIR established caps for sulfur dioxide (SO_2) and NO_x emissions across 28 eastern states and the District of Columbia. In a closely related action, the EPA also formulated a Clean Air Mercury Rule (CAMR) to further reduce pollution throughout the United States.[160] On July 11, 2008, the District of Columbia Court of Appeals issued an opinion that overturned the CAIR and placed other state environmental regulations in question. The EPA filed a petition for rehearing on September 24, 2008.[161] With federal clean air requirements in question and a new Administration, these regulations will remain unclear pending court action on the rehearing appeal.

The EPA's Clean Water Act (CWA) provided 2004 regulations for managing thermal discharges to surface water in the United States. Based on a January 2007 decision by the Second U.S. Circuit Court of Appeals, EPA suspended its Phase II implementation and is considering a new rulemaking.[162] Under new regulations, generators may be required to replace once-through cooling cycles with closed-loop cooling towers.[163] The uncertainty on this issue can pose significant costs for new and existing generators and would reduce the capacity of existing resources through added parasitic loads and unit retirements. A 2008 NERC special assessment projects a 2015 decline in reserve margins from 14.7% to 10.4% when both retirements and cooling system parasitic loads are considered. That represents an approximate 49,000 MW loss of U.S. capacity by 2015.[164]

Market or Regulatory Changes

While many states continue to regulate vertically integrated utility companies and plan for new generation, deregulation and the establishment of

[157] U.S. Department of Energy, "Loan Guarantee Program Press Release," October 29, 2008, http://www.lgprogram.energy.gov/.
[158] U.S. Department of Energy, Office of Nuclear Energy, "DOE Announces Loan Guarantee Applications for Nuclear Power Plant Construction," October 2, 2008, http://www.ne.doe.gov/newsroom/2008PRs/nePR100208.html.
[159] Regional Greenhouse Gas Initiative, "Auction Results," http://www.rggi.org/co2-auctions/results.

[160] Environmental Protection Agency, "Clean Air Interstate Rule," http://www.epa.gov/cair/.
[161] *State of North Carolina v. U.S. Environmental Protection Agency*, Docket No. 05-1244, Environmental Protection Agency, http://www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
[162] United States Environmental Protection Agency, memorandum, "Implementation of the Decision in Riverkeeper, Inc. v. EPA, Remanding the Cooling Water Intake Structures Phase II Regulation," March 20, 2007, http://www.epa.gov/waterscience/316b/phase2/implementation-200703.pdf.
[163] Ibid., 29–30.
[164] North American Electric Reliability Corporation, "2008–2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generation Facilities" (Princeton, NJ: North American Electric Reliability Corporation, October 2008), 4, http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf.

RTOs have brought additional uncertainties to the industry. Market rules continue to change and can be significantly different between RTOs. While the advent of central capacity markets, and particularly forward markets, has helped to create some capacity price certainty, it has been only for relatively short periods. The introduction of energy efficiency programs in capacity markets has created another competitive challenge to generation companies. RTOs such as the California Independent System Operator (CAISO) and the Midwest Independent System Operator (MISO), while trying to mitigate interconnection barriers, are modifying interconnection cost allocations and creating financial uncertainty. RTOs on both coasts are considering environmental concerns and potential ways to help facilitate the entry of variable renewable energy into the marketplace.

At state levels, the regulatory landscape also continues to change. States that fully supported deregulation in the late 1990s and have participated in market dynamics are looking at ways to change energy procurement practices and considering long-term commitments outside of existing markets, even where a competitive market may exist.

Construction, Operating, and Workforce Issues

New generation is expensive. In today's economic environment, the cost to plan, construct, own, and operate a generation station is becoming a much larger obstacle to all companies. Although the current economic downturn has softened commodity prices, the duration of this recession is unclear. Until recently, the costs of raw materials used to construct a power plant were rising sharply. Steel prices rose most steeply, followed by copper, generating equipment, and concrete. According to the U.S. Bureau of Labor Statistics, the cost of electric power generation (including capacity, energy, and ancillary services) rose by 12.9% from September 2007 to September 2008 (see Table 4-1), and general labor costs increased by approximately 3.3%. When taken together, a $1 billion generation project started in today's environment may well cost an additional $2 billion when completed eight years later.

Table 4-1. September 2007–September 2008 Commodity Price Increases

Sept 2007–Sept 2008 Commodity Price Increases	
Steel Mill Products	38.2%
Concrete Products	4.3%
Copper	4.2%
Turbines-Gens	8.6%
Private Industry Labor	3.3%
Electric Power Generation	12.9%

Source: Bureau of Labor Statistics 2008. [165]

The generation industry is also facing soaring global demand for electrical equipment and skilled craftsmen. With new generation construction in developing countries, demand for generators, steam turbines, boilers, and related equipment has increased, driving up prices and extending order lead times from 6–12 months into 2–3 years. The number of skilled craftsmen trained to work on generation systems continues to decline as more of the workforce retires. In 2007, NERC reported that about 40% of senior electrical engineers and shift supervisors in the electric power industry will be eligible to retire in 2009.[166] An informal NERC survey of the industry found that 67% of participants thought there was a high likelihood there would be a reliability risk due to the aging workforce and growing lack of skilled workers.[167] Both electric and water utilities face the prospect of losing up to 60% of their top management and other key workers by 2010.[168] However, NERC's *2008 Long-Term Reliability Assessment* report noted that the industry is making progress in addressing the issue. [169]

Changing fuel costs add to the growing price of generation plants. Central Appalachian coal rose from

[165] U.S. Bureau of Labor Statistics; "Producer Price Index" (Washington, DC: U.S. Bureau of Labor Statistics, 2008), table 2, http://www.bls.gov/news.release/ppi.t02.htm; Ibid., table 5, http://www.bls.gov/ppi/ppitable05.pdf.

[166] North American Electric Reliability Corporation, "Key Issues: Aging Workforce," http://www.nerc.com/page.php?cid=4|53|55.

[167] North American Electric Reliability Corporation, "Results of the 2007 Survey of Reliability Issues" (North American Electric Reliability Corporation, October 24, 2007), 6, http://www.nerc.com/files/Reliability_Issue_Survey_Final_Report_Rev.1.pdf.

[168] "Black & Veatch Launches New Management Succession Planning Service to Address the Aging Workforce," *Business Wire*, June 18, 2007, http://www.allbusiness.com/services/business-services/4513937-1.html.

[169] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment: 2008–2017* (Princeton, NJ: North American Electric Reliability Corporation, October 2008), 5, http://www.nerc.com/files/LTRA2008.pdf.

$45.00 per ton in October 2007 to $119.00 per ton on October 24, 2008. Henry Hub natural gas spot prices rose from $7.80 per million Btu (MMBtu) in June 2007 to $12.70 per MMBtu in June 2008, and then dropped to $6.50 per MMBtu in October 2008 with the economic downturn. New York Mercantile Exchange (NYMEX) heating oil futures rose from $2 per gallon in June 2007 to $3.80 per gallon in June 2008, but also declined to $1.91 per gallon in October 2008. Crude oil futures have seen similar price swings, moving from $65 per barrel in June 2007 to $131 per barrel in June 2008 and falling back to $65 per barrel in October 2008. Higher coal prices and volatile petroleum and natural gas prices, all subject to changing worldwide demand, create a high level of uncertainty for generation projects.[170]

Greening Generation

Twenty-nine states and the District of Columbia have mandated some level of renewable energy for state energy supplies by enacting renewable portfolio standards (RPS). These can vary from set megawatt load levels to various percentages by certain time frames and have provided added incentive for much of the nation's new renewable energy resources.[171] While this may increase energy and capacity prices, it can also help to insulate domestic energy supplies from potential disruptions of international fuel sources. Adding more renewable energy resources increases the diversity and security of domestic energy supplies while providing economic development benefit in those states with renewable resources. Most recently, California's governor has issued an executive order accelerating the use of renewable energy and proposing legislation for one-third of utility supply to be from renewable energy by 2020.

In similar fashion to renewable standards, some states have adopted energy efficiency standards to help offset the need for new generation. Both Texas and North Carolina have requirements for a portion of energy supply to be provided by energy efficiency.[172] As these requirements continue to grow, generation providers will have to adapt to the changing regulatory circumstances and the need for new clean energy resources.

While 58% of states have adopted some form of RPS, the adoption and implementation of a national RPS potentially offers several advantages. Most importantly, it provides incentive to develop new, clean domestic supply resources to help achieve energy security goals. In addition, a national RPS may improve system reliability and can be more cost effective and efficient than individual state models by providing regional flexibility and shifting resource development to regions that have higher levels of renewable resources such as wind, solar, or biomass. A potential drawback is that certain regions with lesser quality renewable resources could also be economically and financially disadvantaged. This concern needs careful consideration in a national program design.

Climate change mitigation and new air quality rules may soon require further minimization of particulates, pollutant gases, and metal compounds, a process that requires expensive and highly technical chemistry.

Traditional generation also creates process waste, whether it is coal ash, spent nuclear fuel rods, cooling water, or flue gas particulate. Containing these wastes is more expensive for some fuel types, and it is difficult to plan for unknown costs of future waste requirements.

Environmental permitting for new generation can also hinder new generation. Existing state and federal laws can require multiple agency applications to secure the necessary permits to build new generation. Cities, counties, and various state agencies typically each have a process mandated by charter or state law. The permitting process in all states is becoming more transparent with active participation by state and federal government; local agencies; and environmental, political, and consumer groups. Planned site use, environmental mitigation (including the use of brownfield sites), and infrastructure security all require negotiation during the development permitting process.

[170] Energy Information Administration, "Coal News and Markets," http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot; Energy Information Administration, "Daily Cushing OK WTI Spot Price FOB," http://tonto.eia.doe.gov/dnav/pet/hist/rwtcd.htm; Energy Information Administration, "Daily New York Harbor No.2 Heating Oil Spot Price FOB," http://tonto.eia.doe.gov/dnav/pet/hist/rhonyhd.htm.

[171] Energy Efficiency and Renewable Energy, "States with Renewable Portfolio Standards," *EERE State Activities and Partnerships* (Washington DC: Energy Efficiency and Renewable Energy, 2008), http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm (accessed November 2008).

[172] Energy Efficiency and Renewable Energy, "Portfolio Standards," *EERE State Activities and Partnerships* (Washington DC: Energy Efficiency and Renewable Energy, 2008), http://apps1.eere.energy.gov/states/alternatives/portfolio_standards.cfm.

Connecting to the Transmission Grid

Connection with the transmission grid in a safe and reliable manner is of utmost importance for new generation. To ensure that new generation can meet these requirements, the transmission owner or RTO typically requires a series of studies that identify necessary upgrades and equipment requirements. The studies determine deliverability and potential costs for interconnection. While necessary, these studies can take more than six months to complete and are further complicated by the continuously changing study profile. The multiplicity of requests and the level of technical detail required in each study can create a significant time lag in the process and can at times be an obstacle to moving forward on a project.

Following the facility study, a formal interconnection agreement must be executed. At this point, the project must make a more significant capital commitment to move forward. Once an interconnection agreement is executed, most projects are considered viable and are included in future reliability studies. Again, the key concern is the uncertain time it can take to complete and execute this agreement.

While the Federal Energy Regulatory Commission (FERC) has prescribed standard interconnection agreements for large and small generators, the entity responsible for the cost of interconnection varies across the nation. Generators pay 100% of the costs of network upgrades necessary for interconnection in the Pennsylvania, New Jersey, Maryland Interconnection (PJM); MISO uses a 50/50 split;[173] and a more recently approved pricing policy provides generators with a potential 100% refund of network upgrade costs necessary for interconnection.[174]

As discussed in Chapter 3 of this report, the availability of transmission can be a significant issue for new generation projects, particularly renewable energy plants. These types of plants are typically sited close to fuel sources or in open rural areas. Wind power farms need areas where there are consistent wind flows, and commercial solar installations need significant open space. Transmission may be located nowhere near these locations. In Texas, recognizing renewable energy transmission constraints, Senate Bill 20 laid the groundwork for large transmission lines to accommodate wind power industry needs and to further accelerate the use of wind power in the state. The Public Utility Commission of Texas approved an approximate $5 billion transmission investment to move 18,456 MW of wind power from western Texas and the Panhandle to metropolitan areas of the state. The cost for this transmission was estimated at $4 per month for every Texas ratepayer, but it helped to eliminate the transmission barrier for wind and solar power in Texas while reducing overall energy prices.

4.3 KEY GENERATION RESOURCES AND THE CHALLENGES THEY FACE

While growth in U.S. electric energy demand has fluctuated from year to year and appears to be slowing as greater efforts are made to tap demand-side resources, demand will increase in our electricity-hungry economy.[175] Meeting this growing demand will require an increasingly diverse generation mix and new generation construction. The following nine fuel types can each play a part in increasing the nation's generation capacity, but they also currently face specific challenges, in addition to those outlined above.

Biomass

Biomass generation facilities tend to be smaller-sized plants to minimize the difficulties with storing, handling, and transporting large quantities of the necessary fuels. While coal has a heat value of 8,000–14,000 Btu per pound, wood and even dried switchgrass have a heat value of around 6,500–7,500 Btu per pound, meaning larger quantities of the fuel

[173] Pennsylvania, New Jersey, Maryland Interconnection LLC, *Open Access Transmission Tariff*, Tariff Sheet 224LL, March 1, 2007; Midwest Independent Transmission System Operator, *Electric Tariff*, Attachment FF, Tariff Sheet 1844, August 25, 2008.

[174] FERC Docket ER08-796, See ITC Midwest, LLC, 124 FERC 61, 150 (2008), and cases cited therein. FERC has approved a pricing policy filed by International Transmission Company, Michigan Electric Transmission Company, and ITC Midwest under which a generator may receive 100% refund of network upgrade costs when a generator has at least a one-year contract to serve the ISO's network consumers or is designated as a network resource at time of commercial operation. In approving this policy, FERC indicated that a 100% reimbursement for network upgrades is just and reasonable, and that different rate proposals can be just and reasonable. The American Transmission Company LLC has refunded 100% of generator interconnection costs since it began operation in 2001.

[175] Energy Information Administration, *Electric Power Annual* (Energy Information Administration, December 2008), table 3.2, http://www.eia.doe.gov/cneaf/electricity/epa/epat3p2.html.

are needed to achieve the same Btu heat input to a generation process. Conversely, landfill gas has a 12,000–13,000 Btu per pound heat content, making it a renewable fuel of choice where available. While biomass fuels may be cost competitive, the quantity needed can impose difficulties. Additionally, generators must manage a complex biomass fuel cycle from start to finish to ensure consistent availability of fuel and to minimize price instability. Principally thought of as wood-burning plants or landfill-gas plants, biomass generation plants are not considered a utility-scale enterprise. As such, biomass projects typically suffer from higher investment costs and a lack of venture capital for new projects. When and where biomass projects have been successful, there have generally been public policies designed to offer project incentives.

As with other renewable fuels, interconnection and transmission costs and the allocation of such costs can be a barrier to new projects. Since many of the projects are smaller, they often must interface with local utilities at retail-level distribution voltages. Unless biomass plants are willing or can sell energy to the local utility, there can be additional energy wheeling costs for handling the energy injection on the distribution system.

Clean Coal Technologies and/or Integrated Gasification Combined Cycle Plants

Clean coal and IGCC plants, while more environmentally friendly, face many of the same challenges as traditional coal plants: they require coal delivery and storage, produce a flue gas with carbon dioxide (CO_2), and have resulting wastes for disposal. Requirements for carbon capture, land-use mitigation, emission control/disposal, and internal energy use required to maintain the gasification and emission processes rapidly increase the costs of such ventures. IGCC plants are estimated to cost 15%–20% more than conventional plants[176] and lose 8%–15% of process efficiency with carbon capture and sequestration.[177] Higher costs and lower outputs will require additional federal support if new IGCC or clean-coal ventures are to be viable.

Carbon capture and sequestration will add both cost and technological difficulties to generation plants. When deciding the location of new plants, generators must consider the transport of fuels to the site and transport of captured carbon to a sequestration location. Mine-mouth coal plants may be replaced by coal plants located near subterranean ground formations that can store carbon, depending on which part of the energy cycle is more costly—fuel procurement or carbon sequestration. The availability of appropriate sites may be a significant barrier to new coal generation, depending on the type of underground formations that can accept and hold carbon emissions. Such sites may also have transmission interconnection barriers where they are far from existing facilities.

Coal generation also continues to have issues with waste storage and disposal. While there are efforts to recycle ash into useful processes, much of it winds up as landfill in carefully prepared dumpsites to limit heavy metal groundwater contamination. According to the American Coal Ash Association (ACAA), the United States produced 125 million tons of coal combustion products in 2006. Of that amount, 43% was used beneficially, leaving approximately 70 million tons for disposal.[178]

Although new coal technologies offer significant improvement, public perception has not reduced barriers for these new plants. Renewable energy generation appears to be the preferred solution, which places new coal technologies at a disadvantage.

Combined Heat and Power and Distributed Generation

Site-by-site environmental and regulatory permitting requirements for CHP and DG plants can be costly and time consuming. Many states still require onerous and expensive interconnection studies, and current policies do not always recognize or reward the avoided emissions from the inherent high-process

[176] Xcel Energy, *Colorado IGCC Demonstration Project* (Minneapolis, MN: Xcel Energy, March 2008), PowerPoint slides, slide 3, http://psc.wi.gov/cleancoal/documents/3-10-06Meeting/XcelDemo.pdf.
[177] Chao Chen, Edward S. Ruben, and Michael Berkenpas, *CO_2 Control Technology Effects On IGCC Plant Performance and Cost*, Proceedings of the 23rd International Coal Conference September 25–28, 2006 (Pittsburgh, PA: Carnegie Mellon University, September 2006), 5, http://www.iecm-online.com/PDF%20files/2006/2006e%20Chen%20et%20al,%2023rd%20Pgh%20Coal%20Conf%20(Sep).pdf.
[178] American Coal Ash Association, "Advancing the Management and Use of Coal Combustion Products," http://www.acaa-usa.org/index.cfm (accessed November 12, 2008).

efficiency for CHP or reduced losses from DG. Additionally, some utilities charge backup or standby rates that can increase the cost of interconnecting to the distribution grid. While there is tremendous opportunity for CHP and DG, it will take a concentrated effort, much like that put forth for renewable energy, to realize the efficiency and environmental benefits this type of generation can offer.

Geothermal

The principal barrier to geothermal generation is finding locations for economical energy production with minimal transmission and interconnection costs.[179] Accessing readily available heat sources in the earth often requires access to rugged and difficult terrain. Once an access point is identified, generators must consider water table concerns, sustainability of heat flows, protected wilderness issues, and transmission availability. Of all the renewable energy generation technologies, geothermal provides the most challenging siting concerns.

Other barriers include relatively lower efficiencies of operation, in comparison to typical coal-fired baseload units, due to lower-temperature steam and the environmental requirements to deal with a fuel containing some heavy metals. While geothermal plants are relatively clean, they can produce some harmful emissions and wastewater that require special disposal processes. Additionally, geothermal plant sizes may be limited by the availability of steam and the geological heat transfer rates at the site.

Geothermal plants are expensive. Financing these plants, together with the risk of steam resource losses, pose ongoing challenges.

Hydroelectric

U.S. hydroelectric generation capacity has declined in recent years. Hydroelectric capacity has decreased from 75.3 gigawatts (GW) in 1990 to 71.8 GW in 2006.[180] In addition to lost capacity, it has also experienced lower energy outputs due to drier weather conditions. Hydroelectric generation dropped to 8% of the nation's supply capacity in 2006.[181]

In terms of barriers to more hydroelectric generation, it is essential to remember an earlier distinction between run-of-the-river hydropower and dam hydropower. Run-of-the-river installations are typically much smaller and have a significantly lower environmental impact. Large dams may require flooding land and may disturb fish migration routes, among other impacts. Consequently, no new large dams have been constructed in the United States in decades.

New technologies such as tidal, wave, and river generation facilities are being explored, but their future is uncertain.

Natural Gas

One of the least expensive types of new generation and the quickest to build, natural gas generation has been the generation resource of choice, as evidenced by the recent increases in gas-fired capacity. Natural gas generation is limited mostly by the cost and availability of natural gas, but it does produce some greenhouse gas emissions. Although a combined-cycle gas plant can produce up to 70% less carbon emissions than a conventional coal plant, it still must contend with the cost of the remaining 30%.

The availability of natural gas has been a concern, although it appears that domestic supplies may be greater than previously thought due to the development of domestic shale gas reserves.

Another potential barrier to new natural gas units in RTO markets may be the ability of gas-fired plants to secure enough capacity and energy revenues to recover their costs. Gas-fired generation has historically been relatively high on the economic dispatch curve and thus has run for shorter periods, largely to meet peak loads.

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[179] California Energy Commission, "Energy Quest," http://www.energyquest.ca.gov/story/chapter11.html. Geothermal energy is often referred to as any energy-producing approach that uses the earth's heat or coolness to improve energy efficiency; for example, groundwater heat pumps can be a geothermal energy product. However, for purposes of this report, geothermal energy is a generation system that uses the earth's heat to produce electric energy. There are many examples of geothermal plants, particularly in California, where there are currently 14 plants in operation.

[180] Energy Information Administration, "Existing Capacity by Energy Source," *Electric Power Annual* (Energy Information Administration, October 22, 2007), http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html.

[181] Ibid.

Nuclear

Nuclear energy power plant planning, if not actual construction, is experiencing a profound upswing, with many generation companies proposing projects. In 2007, the Nuclear Regulatory Commission (NRC) received five applications for new plants. In 2008, the NRC expects to have 13 new applications.[182] While financing this level of construction may be a barrier for some companies, the applications do not reflect this concern. One applicant noted that it expects to seek DOE loan guarantees, with specific financing likely to come from the Federal Financing Bank (FFB), a government entity managed by the U.S. Treasury Department.[183] As discussed previously, available loan guarantees of $18.5 billion have been far oversubscribed by applications to date.

Another barrier for new nuclear generation is the potential for significant cost growth. With escalating material and labor costs, an eight- to nine-year construction project faces significant final cost uncertainty. This increases financial risk and produces higher premiums for secured loans. Because previous nuclear construction projects suffered major cost overruns and left developers in serious financial straits, new nuclear generation projects face significant financing challenges without government support.

The sheer size and capacity of new nuclear facilities also present challenges for the delivery of energy on the existing transmission grid. New 1600 MW nuclear plants will require significant transmission capacity to move energy to markets, which will add additional costs to an already costly effort.

Other barriers to new nuclear plants include the high cost of planning, development, siting, permitting, and litigation where necessary. Worldwide demand for raw materials such as steel, concrete, and uranium fuel has created highly volatile prices. In addition, there is remaining public concern about potentially catastrophic events at nuclear facilities.

Finally, waste disposal and an appropriate mechanism for the long-term storage of spent nuclear fuel await final resolution.

Oil

Oil-fired generation continues to decline in the United States. With environmental concerns, rising fuel prices, and concerns of foreign dependency, it is no longer used in generation except in special circumstances. The principal barriers to new oil-fired generation are the price for fuel, the uncertainty over fuel availability, the cost of carbon emissions, and the fact that all of these variables at highest prices would leave these projects noncompetitive.

Solar

Solar generation, both photovoltaic (PV) and thermal, have significant cost barriers to overcome as a new energy source. PV installations can cost up to 20¢–50¢ per kilowatt-hour (kWh) before incentives, while concentrated thermal installation could cost 15¢–17¢ per kWh.[184] These costs are currently keeping solar generation limited to those locations where public incentives are available and public policy requires use of renewable energy resources. Costs for both PV and thermal generation have, however, been decreasing.

A substantial barrier for solar power is finding appropriate locations where economies of scale can make projects most economic and where interconnection and transmission costs are manageable. Like wind power projects, solar power projects need access to transmission with the capacity to take maximum output; however, there are many times during day and night when that transmission is not utilized. This is true for all variable resources that must plan for maximum output but produce that maximum output of electricity only a portion of the time because sunlight and wind are not always available. Underutilized transmission capacity can add cost to these projects.

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[182] Nuclear Regulatory Commission, “Expected New Nuclear Power Plant Applications,” August 2008, http://www.nrc.gov/reactors/new-licensing/new-licensing-files/expected-new-rx-applications.pdf.

[183] Kevin James Shay, “Nuclear Plant Financing Scarce,” *Gazette.Net*, August 1, 2008, http://www.gazette.net/stories/080108/businew180449_32355.shtml.

[184] Solarbuzz, “Solar Energy Costs/Prices,” *Photovoltaic Industry Statistics: Costs*, http://www.solarbuzz.com/statsCosts.htm (accessed November 12, 2008); Michael Kanellos, “Shrinking the Cost for Solar Power,” *CNET News*, May 11, 2007, http://news.cnet.com/Shrinking-the-cost-for-solar-power/2100-11392_3-6182947.html.

Wind

As of September 3, 2008, U.S. wind generation capacity totaled 20,152 MW.[185] A key barrier to continuing wind power development, as previously discussed, is the uncertainty of the PTC. Long-term extension of this credit and higher prices for renewable energy credits are necessary to secure financing for new projects.[186]

Several wind-power-generation expenses create barriers for new projects. Wind power is a variable generation resource that must pay for high-capacity transmission, but typically only uses about 20%–30% of that capacity in daily generation output. Heavy new demand in the industry has caused temporary shortages and higher prices for turbines, blades, and other construction materials. Finding locations appropriate for facilities with manageable transmission and interconnection costs is also a challenge for new wind power generation efforts. However, states such as Texas are beginning to address this issue by installing new transmission to prime wind power generation sites.

Offshore wind power generation faces similar challenges. Delaware recently announced a contract for its first offshore wind power farm; however, to provide the necessary financial viability, the project required a 20-year purchase arrangement and authorization for the company to earn three renewable energy credits for every 1 MW of renewable energy generation.[187] Rhode Island and New Jersey have also announced the approval of $2 billion and $1 billion offshore wind power farms, respectively, with state financial support.

Offshore wind power projects are typically twice as expensive as land-based ones but offer the opportunity to serve electricity markets in coastal areas where higher costs prevail. The need to construct higher foundations that withstand both wind and wave turbulence in a marine environment adds to the cost of construction. Due to the harsh environment, these facilities require additional maintenance to ensure full lifecycle operation. Permitting for offshore facilities generally requires compliance with both state and federal requirements due to environmental and marine transit issues. The U.S. Minerals Management Service (MMS), charged with permit authority, recently issued its draft permit requirements for offshore wind farms in federal waters. However, with offshore wind farm facilities extending from turbine location to substation landfall, the permitting process will involve almost every interested agency, both federal and state.

The increasing availability of wind power and other variable resources is rapidly changing the system planning environment for transmission systems. Whereas baseload and on-call conventionally fueled peaking plants have typically been used to meet system planning requirements, an increasing portion of today's generation resources is not dispatchable. The variability of wind power as a resource makes this a challenge. As generation increasingly comes from variable resources, reliability organizations will need to plan for enough flexible supply and/or demand resources to allow for system balancing. Developers who wish to cluster units for economic advantage may begin to see new challenges created by reliability concerns.

4.4 Recommendations to DOE

Encouraging and managing new generation technologies while removing barriers to their development require bold new actions.
For example, in DOE's *20% Wind Energy by 2030* report, DOE notes that "the 20% Wind Power Scenario is not likely to be realized in a business-as-usual future. Achieving this scenario would involve a major national commitment to clean, domestic energy sources with minimal emissions of GHGs [greenhouse gases] and other environmental pollutants."[188]

The Electricity Advisory Committee has identified seven recommendations to DOE to enhance generation development:

[185] American Wind Energy Association, "U.S. Wind Energy Installations Surpass 20,000 Megawatts," News Releases and Statements, September 3, 2008.
[186] American Wind Energy Association, "Wind Power Outlook 2008" (Washington, DC: American Wind Energy Association, 2008), http://www.awea.org/pubs/documents/Outlook_2008.pdf.
[187] Delaware State Senate, *An Act To Amend Title 26 of The Delaware Code Relating to Offshore Wind Power Installations*, Senate Bill 328, 144th General Assembly, http://legis.delaware.gov/LIS/LIS144.NSF/vwLegislation/SB+328?Opendocument.
[188] U.S. Department of Energy, *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply* (Washington, DC: U.S. Department of Energy, 2008), http://www.20percentwind.org/20percent_wind_energy_report_revOct08.pdf.

1. Reduce the risks faced by new generation developers and electricity consumers by supporting financial grants and ensuring continued funding for loan guarantees.

Even if generation projects obtain all necessary regulatory approvals and comply with applicable environmental standards, they still face an extremely significant barrier—the financial viability of the proposed project. DOE must, therefore, support policies, programs, and legislation that minimize the risk of cost recovery and provide returns appropriate to the risk of each such project. DOE should consider the following potential tactics:

- Continue to provide financial grants for new and enhanced technologies, and expand grant programs to support planning and development of new generation projects that demonstrate clean and/or renewable resources and environmental benefits.
- Ensure continued funding for and availability of federal loan guarantees for new energy technologies.
- In addition to the above mechanisms for reducing risks, collaborate with state regulators and state economic development offices to ensure timely recovery of new generation investment in regulated states as well as competition for demonstration projects in all states.

2. Promote long-term policies, processes, and legislation that increase investor certainty and reflect the 30-year or longer lives of electricity generation plants by expanding PTCs and promoting the use of long-term investment contracts for new technologies.

In the generation industry, long term is considered the 30–40 year life of a plant. Yet, federal and state governments discuss and produce legislative changes for energy almost annually. The need for longer-term policy consistency conflicts with short-term legislative actions, creating detrimental uncertainty for new generation and new technology development. The recent one-year extension of the PTC and an impending carbon emissions program, for example, make it impossible for generation developers to predict and plan for requirements. The 2008 National Governors Association Policy Position, NR-18, Section 18.1.3, echoes the need for long-term legislative thinking in the energy sector and is a good source for additional recommendations.[189] More specific suggestions for DOE's consideration include:

- Advocate the continuation and establishment of PTCs, the expansion of investment tax credits, and the provision of comparable incentives for not-for-profit generators for a much longer term to provide additional financial certainty for new generation projects.
- Promote the use of long-term investment contracts through preferential grants and loans for new technologies that offer long-term generation output contracts.

3. Advocate improved and longer-term certainty for air quality, water quality, and carbon emission requirements that will support the development of new generation technologies and provide needed certainty for all new generation.

- Advocate the adoption of cost-effective long-term national policies for carbon restrictions, air quality rules, and waste disposal that support the development of new generation technologies and add longer-term environmental compliance certainty for all generation companies.
- Adopt policies that coordinate the environmental limitations imposed by legislation or regulatory actions with the types of new generation needed to comply.
- Support the adoption of new air- and water-quality standards that maintain environmental quality while creating long-term certainty.

[189] National Governors Association, "NR-18: Comprehensive National Energy and Electricity," *Policy Position* (Washington, DC: National Governors Association, July 2008), http://www.nga.org/portal/site/nga/menuitem.8358ec82f5b198d18a278110501010a0/?vgnextoid=2a2b9e2f1b091010VgnVCM1000001a01010aRCRD.

4. Continue supporting through grant and loan guarantee programs the development of new technologies, technology enhancements, and improved manufacturing processes for generation equipment.

Innovation drives the development of new and efficient generation technologies. DOE must continue and enhance its support for generation research, development, and deployment.

- Adopt a long-term funding plan that provides a stable level of support for new generation programs and technologies and guides direction and purpose.
- Support efforts to bring to market efficient, cost-effective technology advancements and improved manufacturing processes in generation equipment.

5. Support the development and expansion of distributed and renewable energy generation.

Distributed and renewable energy generation have the ability to play a much larger role in securing adequate generation and need to be considered in state and RTO planning processes.

- Support revisions to regional and interregional planning processes that permit RTOs to solicit and incorporate both cost-effective generation and energy efficiency resources in long-term supply plans.
- Explore and promote the potential for distributed, renewable energy generation and high-efficiency CHP to help meet supply requirements.
- Assess the potential for a national renewable portfolio standard to encourage efficient clean energy development, increased energy independence, and security.
- Support the development of standards and tariffs for reliably interconnecting renewable and distributed generation.
- Support distributed generation emission requirements that are based on power output as opposed to fuel input to encourage more efficient use of fuels.

6. Evaluate the status of generation adequacy in each region of the country in order to evaluate ways to improve performance.

Generation adequacy varies throughout the country due to a variety of factors, including regulatory regimes, investment climate, and market conditions. DOE should conduct an inventory of how the various regions are faring in terms of generation adequacy, together with lessons learned and recommendations for improvements.

7. With the goal of assisting both public- and private-sector decision makers responsible for allocating generation investment, convene a review of generation technologies in a manner that integrates electric system reliability, consumer affordability, and environmental impacts.

Generation investments are particularly challenging today for both regulators and investors, in light of urgent combined concerns about affordability, public health, and climate change. Rapid changes in both technologies and costs render most available studies of limited value to those trying to decide whether and how to invest scarce capital dollars. DOE could assist all parties by convening a comprehensive technology assessment designed to assess the most significant economic and environmental dimensions of these choices.

8. Advocate policies, processes, and legislation that fairly allocate interconnection and integration costs of new generation to the grid.

The cost of building transmission facilities, particularly for renewable energy generation plants located in rural or remote areas, can be a significant cost barrier for most new generation projects.

Adequate investment in the nation's transmission system is essential so that the electricity generated throughout the United States can be delivered to urban centers that need the increased supply. DOE should:

- Advocate a fair and equitable interconnection cost allocation process that balances costs and benefits for transmission owners, generators, and consumers.

9. Promote improved planning processes that expedite generation facility studies and interconnection agreements, and consider generation, demand response / load management, and storage solutions for reliability.

RTOs have a significant number of generation projects awaiting the facility studies that identify preliminary interconnection requirements and costs. Delays in the review process make time projections uncertain and impact project viability. Recommended DOE actions to enhance and improve that process include:

- Advocate for more accurate and timely interconnection study processes for generation and transmission developers.
- Conduct with other interested agencies a national review of generation planning processes, including their relationship to transmission planning and demand response / load management options.

Acronyms

AC	alternating current
ACAA	American Coal Ash Association
ACEEE	American Council for an Energy-Efficient Economy
AGC	automatic generation control
APC	air pollution control
APS	American Physical Society
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
AWEA	American Wind Energy Association
BLM	U.S. Bureau of Land Management
BLS	U.S. Bureau of Labor Statistics
BPA	Bonneville Power Administration
Btu	British thermal unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CCCT	combined cycle combustion turbine
CEC	California Energy Commission
CEE	Consortium for Energy Efficiency
CH_4	methane
CHP	combined heat and power
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CRA	Charles River Associates
CREZ	Competitive Renewable Energy Zone
CWA	Clean Water Act
DG	distributed generation
DNI	direct normal insolation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewable Energy
DSM	demand-side management

E3	Energy and Environmental Economics, Inc.
EAB	Electricity Advisory Board
EAC	Electricity Advisory Committee
EE	energy efficiency
EEI	Edison Electric Institute
EF	Energy Foundation
EHV	extra-high voltage
EIA	Energy Information Administration
EMS	Energy Management System
EPA	U.S. Environmental Protection Agency
EPAct 1992	Energy Policy Act of 1992
EPAct 2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FACTS	flexible alternating current transmission system
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
FRCC	Florida Reliability Coordinating Council, Inc.
GAO	U.S. Government Accountability Office (Prior to July 7, 2004, the GAO was called the "General Accounting Office")
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt hour
HVAC	heating, ventilation, and air conditioning
HVDC	high-voltage direct current
ICC	International Code Council
ICF	insulating concrete forms; also ICF, Inc. (a consulting firm specializing in energy and environmental issues)
IGCC	integrated gasification combined cycle
IOU	investor-owned utility
IRP	integrated resource plan (or planning)
ISO	independent system operator
ISO-NE	Independent System Operator of New England
ITC	International Transmission Company
JCSP	Joint Coordinated System Plan
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LFG	landfill gas
LNG	liquefied natural gas

LTRA	*Long-Term Reliability Assessment*, an annual NERC publication
METC	Michigan Electric Transmission Company
MGA	Midwestern Governors Association
MISO	Midwest Independent Transmission System Operator
MMBtu	million British thermal units
MMS	U.S. Minerals Management Service
MRI	magnetic resonance imaging
MRO	Midwest Reliability Organization
MS	Master of Science
MSW	municipal solid waste
MW	megawatt
MWh	megawatt hour
NAE	National Academy of Engineering
NAESB	North American Energy Standards Board
NAPEE	National Action Plan for Energy Efficiency
NARUC	National Association of Regulatory Utility Commissioners
NASPI	North American SynchroPhasor Initiative
NCEP	National Commission on Energy Policy
NEEP	Northeast Energy Efficiency Partnerships
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NIETC	National Interest Electric Transmission Corridor
NO_x	nitrogen oxide
NPCC	Northwest Power and Conservation Council
NPCC	Northeast Power Coordinating Council, Inc.
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRRI	National Regulatory Research Institute
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
OE	Office of Electricity Delivery and Energy Reliability
PCAST	President's Council of Advisors on Science and Technology
PhD	Doctor of Philosophy
PHEV	plug-in hybrid electric vehicle
PJM	Pennsylvania, New Jersey, Maryland Interconnection LLC
PMA	power marketing administration
PMU	phasor measurement unit

PNNL	Pacific Northwest National Laboratory
POLR	Provider of Last Resort
PSE	Puget Sound Energy
PTC	production tax credit
PUC	public utilities commission
PUCT	Public Utility Commission of Texas
PURPA	Public Utilities Regulatory Policies Act of 1978
PV	photovoltaic
R&D	research and development
RGGI	Regional Greenhouse Gas Initiative
RMATS	Rocky Mountain Area Transmission Study
RPM	Reliability Pricing Model
RPS	renewable portfolio standard
RTO	Regional transmission organization
RUS	Rural Utilities Service
SCADA	supervisory control and data acquisition
SEPA	Southeastern Power Administration
SFV	straight-fixed variable
SO_2	sulfur dioxide
SO_x	sulfur oxide
SPP	Southwest Power Pool
SWPA	Southwestern Power Administration
TDU	transmission-dependent utility
TEPPC	Transmission Expansion Policy Planning Committee
TVA	Tennessee Valley Authority
TW	terawatt
TWh	terawatt hour
UMTDI	Upper Midwest Transmission Development Initiative
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
WREZ	Western Renewable Energy Zone

Glossary

advanced metering systems: Electricity meters that measure and record usage data at hourly intervals at a minimum, and provide usage data to both consumers and energy companies at least once daily.

automatic generation control (AGC): The main wide-area control in use today which controls tie-line power flows and generator outputs.

anthropogenic: Caused or produced by humans.

asset cost recovery: Recovering capital investment costs through charges to ratepayers.

bag house process: A process in which Air Pollution Control (APC) equipment is designed and deployed around the use of engineered fabric filter tubes, envelopes, or cartridges in the dust capturing, separation, or filtering process.

baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

baseload plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

behind the meter generation: From the utility perspective, small sized and distributed generation that is considered a demand reduction rather than a source of supply.

biogas: A gas produced by the biological breakdown of organic matter in the absence of oxygen. Biogas originates from biogenic material and is a type of biofuel.

biomass: A renewable fuel comprised of agricultural waste, municipal solid waste, or woody products that is burned to heat water, creating steam that turns turbines that generate electricity.

bulk power supply: The holistic infrastructure used to provide the electricity service to all consumers.

bundled utility service: Generation, transmission, and distribution services provided by one entity for a single charge. This service would include ancillary services and retail services.

capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

capacity factor: The ability of a generation unit to provide peaking capacity as well as a flexible dispatchable form of energy.

capacity (purchased): The amount of energy and capacity available for purchase from outside the system.

carbon sequestration: The capture and storage of CO_2 in underground facilities or natural caverns to prevent it from being released into the atmosphere.

carbon tax: An environmental tax on emissions of carbon dioxide and other greenhouse gases. It is an example of a pollution tax.

circuit: A conductor or system of conductors through which electricity is intended to flow.

Clean Air Interstate Rule (CAIR): Issued by EPA in March, 2005; designed to achieve the largest reduction in air pollution in more than a decade. It established caps for SO_2 and NO_x emission across 28 eastern states and the District of Columbia. The rule is still pending in court.

Clean Air Mercury Rule: Issued by EPA; challenged by utilities in court and is still pending.

climate change: A term used to refer to all forms of climatic variability, but especially to significant change from one prevailing climatic condition to another. In some cases "climate change" has been used synonymously with the term "global warming"; scientists, however, tend to use the term in a wider sense inclusive of natural changes in climate, including climatic cooling.

coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50% by weight and more than 70% by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

coal-fired steam plant: An electricity-generation plant that uses coal to boil water into steam to turn a steam turbine.

cogeneration: The process in which fuel is used to produce heat for a steam turbine or gas for a turbine. The turbine drives a generator that produces electricity, with the excess heat used for process steam.

combined cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

combined heat and power (CHP): See "cogeneration."

Competitive Renewable Energy Zone (CREZ): Geographic zones designated by the Public Utility Commission of Texas (PUCT) and Electric Reliability Council of Texas (ERCOT) as having renewable energy potential of 1,000 MW or greater and suitable land areas sufficient to develop generating capacity from renewable energy technologies. These were defined in order to develop transmission capacity necessary to deliver the electric output from renewable energy technologies in the competitive renewable energy zones in a manner that is most cost-effective to electric consumers.

concentrating solar energy: Energy that is harnessed from sunlight reflected by mirrors and directed at a receptor to heat water, creating steam to turn turbines.

congestion: A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

control center: A room wherein utility personnel use control equipment to operate the utility's infrastructure assets.

cooperative electric utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

cyber security: Ensuring the safety of computerized control systems for critical infrastructure.

decoupling: The disassociation of utility profits from its sales of electricity. Under this system, a rate of return is aligned with meeting revenue targets, and rates are increased or decreased to meet the target at the end of the adjustment period.

demand (electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

demand response / load management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy efficiency standards. Demand-side management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

demand-side planning ("first fuel" approach): Adoption of targets such as 15-by-15 or 20-by-20, meaning 15% or 20% load reduction by 2015 or 2020, respectively. Such targets are generally set based on studies on the cost-effective demand-side resource available. This resource is factored into load forecasts.

dispatching: The process by which grid operators control delivery of power to the system from connected power plants.

distributed electric generation: Generic term for any electric generator located near the point where the power is used.

Electric Reliability Organization (ERO): A FERC-designated not-for-profit, self-regulating industry entity that enforces mandatory reliability standards through an industry-driven collaborative process. The North American Electric Reliability Corporation (NERC) is the ERO.

energy storage: Facilities that store potential energy so it can be used to produce electricity whenever needed to meet demand. Examples include pumped storage, fuel cells, batteries, and flywheels.

electric utility: Any entity that generates, transmits, or distributes electricity and recovers the cost of its generation, transmission or distribution assets and operation, either directly or indirectly, through cost-based rates set by a separate regulatory authority (e.g., state Public Utility Service Commission), or is owned by a governmental unit or the consumers that the entity serves. Examples of these entities include: investor-owned entities, public power districts, public utility districts, municipalities, rural electric cooperatives, and state and federal agencies.

electricity: The flow of electric current from an energy source.

energy efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating, and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Policy Act of 2005 (EPAct): The Energy Policy Act of 2005 is a federal statute that was passed by the United States Congress on July 29, 2005 and signed into law on August 8, 2005. The Act was intended to augment the Energy Policy Act of 1992 in combating growing energy problems through the use of tax incentives and loan guarantees for energy production of various types.

energy receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

energy source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

extra-high voltage (EHV): 345 kV and higher voltage transmission lines, including High Voltage Direct Current.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the U.S. Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

flexible alternating current transmission systems (FACTS): A system comprised of static equipment used for the AC transmission of electrical energy. It is meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based device.

flue gas: The combustion exhaust gas produced at power plants.

formula rates: State-approved mechanism to allow automatic recovery of FERC-approved investments.

free-ridership: When one consumes more than their fair share of a resource, or shoulders less than a fair share of the costs of its production. Free riding is usually only considered an economic "problem" when it leads to the non-production or under-production of a public good.

generation (electricity): The process of converting non-electrical energy to electricity.

geothermal resource: The interior of the earth is very hot. Geothermal resources are deposits of hot water or hot rock, the heat from which can be used to make steam and turn turbines for the generation of electricity.

grid: An electric transmission and/or distribution system.

high-voltage direct current (HVDC): A technology that enables direct current to be sent long distances by increasing the voltage. This technology requires the use of converter stations at either end of the cable that change the current from AC to DC and from DC back to AC.

human capital: Trained or educated personnel.

hydroelectric energy: Electricity produced when falling water is used to turn turbines.

independent system operators (ISO): An independent, federally-regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.

interconnection: See “grid.”

investment tax credit: The recognition of partial payment already made towards taxes due through the investment in cleaner technologies.

investor-owned utility (IOU): A class of utility whose stock is publicly traded and which is organized as a tax-paying business; usually financed by the sale of securities in the capital market. It is regulated and authorized to achieve an allowed rate of return.

lake effect: A recurrent power flow problem in the Great Lakes area.

levelized costs: A reflection of all-in costs of owning, operating and purchasing fuel for generating technologies.

liquefied natural gas (LNG): Natural gas (primarily methane, CH_4) that has been converted to liquid form for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas. It is odorless, colorless, non-toxic, and non-corrosive.

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

mandatory reliability standards: Standards intended to maintain the reliability and adequacy of the bulk power transmission system. These standards, developed by NERC with the assistance of industry partners, and oversight by FERC, went into effect in June of 2007. Violations of these standards can result in substantial monetary penalties.

megawatt-hour (MWh): One million watts acting over a period of 1 hour. The MWh is a unit of energy.

National Action Plan for Energy Efficiency (NAPEE): DOE/EPA plan to foster the collaborative efforts of key energy market stakeholders including utilities, regulators, consumers, and partnership organizations in an effort to establish and further a national commitment to energy efficiency.

natural gas: Naturally-occurring deposits of methane (CH_4) and related compounds. Natural gas is a fossil fuel, and is converted to water and CO_2 when burned.

National Cap and Trade Program: A proposal to create a carbon market in an effort to curb CO_2 emissions.

non-dispatchable: Intermittent or variable generation resources (such as wind) are considered “non-dispatchable” because they may not be available when electricity is needed to serve load.

North American SynchroPhasor Initiative (NASPI): A precise time synchronized system for measuring power flows on an interconnection-wide basis; used as a diagnostic tool to assess the state of the electric grid.

nuclear energy: Energy that comes from splitting atoms of radioactive materials, such as uranium.

nuclear reactor: A device in which a nuclear fission chain reaction occurs under controlled conditions so that the heat yield can be harnessed to boil water for the production of electricity.

Open Access Transmission Tariffs (OATTs): A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.

pass-through rates: State-approved mechanism to allow automatic recovery of FERC-approved investments.

peak demand / peak load: The maximum load during a specified period of time.

peak power: The time of day when there is the most demand for electricity, requiring more power from the electrical grid.

peaking capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

peaking plant: A plant usually housing low-efficiency steam units, gas turbines, diesels, or pumped storage hydroelectric equipment; normally used only during peak-load periods.

photovoltaic (PV): Pertaining to the direct conversion of light into electricity.

plug-in hybrid electric vehicle (PHEV): A hybrid vehicle with batteries that can be recharged by connecting a plug to an electric power source. It shares the characteristics of both conventional hybrid electric vehicles and battery electric vehicles, having an internal combustion engine and batteries for power.

power electronics: Electronic-equipped devices, such as switches, inverters, and controllers, that allow electric power to be controlled precisely and rapidly to support long-distance transmission.

power purchase agreement: A contract for a large consumer to buy electricity from a power plant. This is usually the most important contract underlying the construction and operation of a power plant.

production tax credit (PTC): Production tax credits support the introduction of renewable energy by allowing companies which invest in renewable energy to write off this investment against other investments they make. A PTC can be used as the central mechanism for the support of renewable energy as part of a national or regional mechanism, or it can be used in support of other mechanisms, such as a quota mechanism.

public benefit fund: State funds dedicated to energy efficiency and renewable energy projects. The funds are collected either as a small fee on consumer electricity bills or as contributions from utilities.

public utility commissions (PUC): A state agency that regulates the rates and services of a public utility serving consumers within that state.

Regional Greenhouse Gas Initiative (RGGI): An initiative in New England that established a cap and trade program to reduce carbon emissions 10% by 2019 for participating states.

regional transmission organization (RTO): An entity responsible for planning and operating a region's transmission network.

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

reliability: Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

reliability pricing model (RPM): An institutional arrangement devised by PJM intended to incent new investment where it is most needed by offering enhanced capacity payments.

renewable fuels: Renewable fuels are assumed to be virtually inexhaustible over the long term but limited in the amount of energy that is available during any given unit of time. Some forms (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades or centuries they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar, and wind power. In the future, renewable fuels could also include the use of ocean thermal, wave, and tidal action technologies.

renewable portfolio standards (RPS): Standards that mandate that a specific percentage of electric power supplied at retail be obtained from qualifying renewable energy technologies.

reserve margin (operating): The amount of unused available capability of an electric power system at peak-load for a utility system as a percentage of total capability.

Rural Utilities Service (RUS): A program of the U.S. Department of Agriculture that lends money to rural co-operatives.

shale gas: A form of natural gas produced from some shale rock formations. Because shales ordinarily have insufficient permeability to allow significant fluid flow to a well bore, most shales are not sources of natural gas.

siting: The process of approving a location for generation, transmission, or other energy infrastructure.

Smart Grid: A sophisticated two-way communication system for managing the electric infrastructure.

solar energy: The radiant energy from the sun, which can be converted into other forms of energy, such as heat or electricity.

spillover effects: Unintended consequences of economic activities or processes; also called "externalities."

subsidies: A form of financial assistance paid to a business or economic sector. A subsidy can be used to support businesses that might otherwise fail, or to encourage activities that would otherwise not take place.

supervisory control and data acquisition (SCADA): Centralized systems which monitor and control entire sites, or complexes of systems spread out over large areas (on the scale of kilometers or miles). In terms of electricity, SCADA refers to the system that monitors and controls the electricity transmission and distribution system.

supply-side resources: Electricity generation resources (i.e., power plants), that physically supply electricity into the electric system for delivery to consumers. These do not include demand-side alternatives such as energy efficiency and demand response.

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

terrestrial footprint: The area of land that is utilized for the building of infrastructure.

tie-line: A connection between electrical lines.

transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed to a lower voltage for distribution to the consumer.

Western Climate Initiative: A program including seven western states and several Canadian provinces that seeks a 15% reduction of carbon emissions below 2005 levels by 2020 by employing a cap and trade program.

wide-area measurement systems (WAMS): Wide-area, real-time, geographical displays of the power grid using data generated every four seconds from more than 100 control areas in the United States It provides the North American Electric Reliability Corporation with immediate alerts that the balance between generation and load has deviated significantly from scheduled values in specific control areas, and provides the location and amount of this deviation. This simultaneous alert to reliability coordinators and operators allows them to work together to implement corrective action and move the system back to normal conditions. WAMS is also being used by NERC Reliability Subcommittees and Working Groups for reliability performance tracking, analysis, and resource inadequacy post-assessment.

wind energy: Kinetic energy present in wind motion that can be converted into mechanical energy for driving pumps, mills, and electric power generator.

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