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Renewable Electricity Futures Study

Bulk Electric Power Systems: Operations and Transmission Planning

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Renewable Electricity Futures Study

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Renewable Electricity Futures Study

Volume 4: Exploration Bulk Electric Power Systems: Operations and Transmission Planning

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Perspective

The Renewable Electricity Futures Study (RE Futures) provides an analysis of the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the U.S. electric system. The study is not a market or policy assessment. Rather, RE Futures examines renewable energy resources and many technical issues related to the operability of the U.S. electricity grid, and provides initial answers to important questions about the integration of high penetrations of renewable electricity technologies from a national perspective. RE Futures results indicate that a future U.S. electricity system that is largely powered by renewable sources is possible and that further work is warranted to investigate this clean generation pathway. The central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States.

The renewable technologies explored in this study are components of a diverse set of clean energy solutions that also includes nuclear, efficient natural gas, clean coal, and energy efficiency. Understanding all of these technology pathways and their potential contributions to the future U.S. electric power system can inform the development of integrated portfolio scenarios. RE Futures focuses on the extent to which U.S. electricity needs can be supplied by renewable energy sources, including biomass, geothermal, hydropower, solar, and wind.

The study explores grid integration issues using models with unprecedented geographic and time resolution for the contiguous United States. The analysis (1) assesses a variety of scenarios with prescribed levels of renewable electricity generation in 2050, from 30% to 90%, with a focus on 80% (with nearly 50% from variable wind and solar photovoltaic generation); (2) identifies the characteristics of a U.S. electricity system that would be needed to accommodate such levels; and (3) describes some of the associated challenges and implications of realizing such a future. In addition to the central conclusion noted above, RE Futures finds that increased electric system flexibility, needed to enable electricity supply-demand balance with high levels of renewable generation, can come from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations. The analysis also finds that the abundance and diversity of U.S. renewable energy resources can support multiple combinations of renewable technologies that result in deep reductions in electric sector greenhouse gas emissions and water use. The study finds that the direct incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Of the sensitivities examined, improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. Assumptions reflecting the extent of this improvement are based on incremental or evolutionary improvements to currently commercial technologies and do not reflect U.S. Department of Energy activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

RE Futures is an initial analysis of scenarios for high levels of renewable electricity in the United States; additional research is needed to comprehensively investigate other facets of high renewable or other clean energy futures in the U.S. power system. First, this study focuses on renewable-specific technology pathways and does not explore the full portfolio of clean technologies that could contribute to future electricity supply. Second, the analysis does not attempt a full reliability analysis of the power system that includes addressing sub-hourly, transient, and distribution system requirements. Third, although RE Futures describes the system characteristics needed to accommodate high levels of renewable generation, it does not address the institutional, market, and regulatory changes that may be needed to facilitate such a transformation. Fourth, a full cost-benefit analysis was not conducted to comprehensively evaluate the relative impacts of renewable and non-renewable electricity generation options.

Lastly, as a long-term analysis, uncertainties associated with assumptions and data, along with limitations of the modeling capabilities, contribute to significant uncertainty in the implications reported. Most of the scenario assessment was conducted in 2010 with assumptions concerning technology cost and performance and fossil energy prices generally based on data available in 2009 and early 2010. Significant changes in electricity and related markets have already occurred since the analysis was conducted, and the implications of these changes may not have been fully reflected in the study assumptions and results. For example, both the rapid development of domestic unconventional natural gas resources that has contributed to historically low natural gas prices, and the significant price declines for some renewable technologies (e.g., photovoltaics) since 2010, were not reflected in the study assumptions.

Nonetheless, as the most comprehensive analysis of U.S. high-penetration renewable electricity conducted to date, this study can inform broader discussion of the evolution of the electric system and electricity markets toward clean systems.

The RE Futures team was made up of experts in the fields of renewable technologies, grid integration, and end-use demand. The team included leadership from a core team with members from the National Renewable Energy Laboratory (NREL) and the Massachusetts Institute of Technology (MIT), and subject matter experts from U.S. Department of Energy (DOE) national laboratories, including NREL, Idaho National Laboratory (INL), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories (SNL), as well as Black & Veatch and other utility, industry, university, public sector, and non-profit participants. Over the course of the project, an executive steering committee provided input from multiple perspectives to support study balance and objectivity.

RE Futures is documented in four volumes of a single report: Volume 1 describes the analysis approach and models, along with the key results and insights; Volume 2 describes the renewable generation and storage technologies included in the study; Volume 3 presents end-use demand and energy efficiency assumptions; and this volume—Volume 4—discusses operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

List of Acronyms

AC	alternating current
AGC	automatic generation control
BA	balancing area
Btu	British thermal unit
CAISO	California ISO
CREZ	Competitive Renewable Energy Zones
CSP	concentrating solar thermal power plants
DC	direct current
EIA	U.S. Energy Information Administration
ELCC	effective load-carrying capability
EPACT 1992	Energy Policy Act of 1992
ERCOT	Electric Reliability Council of Texas
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
HVDC	high-voltage direct current
Hz	Hertz
ISO	Independent System Operator
kW	kilowatt
kWh	kilowatt-hour
LMPs	locational marginal prices
LOLE	loss-of-load expectation
LOLP	loss-of-load probability
MISO	Midwest ISO
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NYISO	New York ISO
PJM	Pennsylvania, New Jersey, and Maryland RTO
PV	photovoltaic
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment Systems
RSG	reserve-sharing group
RTO	Regional Transmission Organization
WWSIS	Western Wind and Solar Integration Study

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Introduction

Today, the U.S. electric grid faces a number of technical and institutional challenges, including integrated management of both loads and generation, supporting wholesale electricity markets, facilitating customer participation in the marketplace, reducing carbon emissions, and reducing dependence on petroleum by electrifying transportation. Technical issues associated with these changes challenge legacy grid planning and operational practices, and they will likely require substantial, or perhaps even transformational, changes for the U.S. grid to respond effectively. The rapid deployment of renewable electricity—particularly the addition of 40,000 MW of wind generation—to the U.S. grid over the last 10 years is one driver of change. The Renewable Electricity Futures Study (RE Futures) examines the implications and challenges of renewable electricity generation levels—from 30% up to 90% of all U.S. electricity generation from renewable technologies—in 2050. Additional sensitivity cases are focused on an 80%-by-2050 scenario. At this 80% renewable generation level, variable generation from wind and solar resources accounts for almost 50% of the total generation. At such high levels of renewable electricity generation, the unique characteristics of some renewable resources, specifically resource geographical distribution, and variability and uncertainty in output, pose challenges to the operability of the U.S. electric system.

RE Futures is documented in four volumes. Volume 1 describes the analysis approach and models, along with the key results and insights. Volume 2 describes the renewable generation and storage technologies included in the study. Volume 3 presents end-use demand and energy efficiency assumptions. Volume 4 (this volume) focuses on the role of variable renewable generation in creating challenges to the planning and operations of power systems and the expansion of transmission to deliver electricity from remote resources to load centers. The technical and institutional changes to power systems that respond to these challenges are, in many cases, underway, driven by the economic benefits of adopting more modern communication, information, and computation technologies that offer significant operational cost savings and improved asset utilization. While this volume provides background information and numerous references, the reader is referred to the literature for more complete tutorials.[1]

This volume also provides an overview of today's electric power system (the grid), including how planning and operations are carried out to ensure reliability. It then explores the challenges to the grid posed by high levels of variable renewable generation and some changes that are expected to occur in response to these challenges. Finally, this volume concludes with a discussion of the capacity expansion and production cost models used in RE Futures and how they represent the operational issues discussed earlier.

[1] For a full tutorial on the basics of power systems, see Casazza and Delea (2010) and Brown and Sedano (2004).

Chapter 22. The North American Electric Power System: The Grid

The electric power system is the infrastructure that converts fuel and energy resources into electric power (thus generating electricity) and carries and manages that electric power from where it is generated to where it is used.[2] It is a system of systems that comprises physical networks that include fuel and resources; power plants of many different varieties; electric transmission and distribution line networks and measurement; information and control systems; and virtual networks of money, business relationships, and regulation. Achieving balance among all of these elements is a fundamental challenge for the planning, engineering, and operation of the overall system because of the variability and uncertainty of load and unexpected equipment failures that affect the generation and delivery of electricity. The system of systems is loosely referred to here as "the grid."

The major physical elements of the grid are generation, transmission, distribution, and load. Generation is the collection of power plants electrically connected to the grid and ranging in size from very small, distributed units[3] to central stations rated at over 1,000 MW (Casazza and Delea 2010). Transmission is the collection of networked high-voltage lines (above 100 kV) that tie generation to load centers. High-voltage lines also connect utilities to one another, reduce costs through sharing of resources, and provide enhanced reliability in case of events such as the loss of a large generator. The high-voltage transmission system also enables the wholesale marketplace for electricity. In general, the bulk or wholesale system refers to the network of interconnected generation and transmission lines, while the distribution system refers to the lower-voltage generally radial lines that deliver electricity to the final customer. The load—created by the electrical equipment on the customer's side of the meter—is electrically part of the overall power system and affects its operation; load completes the system. The largest industrial and commercial customers may be served by transmission directly; the rest are served by the lower-voltage distribution system.

When the development of electric power began more than 130 years ago, generating plants were isolated and served dedicated customers. Over the next several decades, "utilities" began linking multiple generating plants into isolated systems. By the mid-1920s, it was clear that connections among utility systems could provide additional reliability and savings with fewer cumulative resources. The connection of neighboring utilities provided access to generation reserves in times of equipment failure, unexpected demand, or routine maintenance, as well as improved economics through reserve sharing and access to diverse and lower-cost energy resources. The U.S. grid today is the result of a complex web of legacy designs developed from the early 1920s to the present. By the 1980s, the North American electric system had been transformed from isolated utilities to an interregional grid spanning the continent.

The three large areas or "interconnections" that operate as synchronous[4] interconnected systems in the contiguous United States, Canada, and a small portion of Mexico are the Western

[2] Electric power is in units of watts and electricity is in units of watt-hours; they are often used interchangeably.
[3] Many small distributed generators or small power units are installed at hospitals, fire stations, and other critical facilities to provide power in case of emergencies or failure of the grid resulting in an interruption of the flow of electricity. These standby or emergency backup systems are not normally electrically connected to the grid. With the addition of proper control and switching systems, these units could be connected.
[4] All of the generators are operating at the same synchronous frequency of 60 Hertz, producing AC electricity.

Interconnection, the Eastern Interconnection, and Electric Reliability Council of Texas (ERCOT) in Texas (Figure 22-1). The three interconnections are connected by a small number of DC connections with very limited transfer capacity.[5] Quebec is also connected to the United States and neighboring Canada with HVDC ties. Alaska and Hawaii have their own systems.

Many entities—balancing authorities, regional entities, utilities, power pools, independent system operators (ISOs), regional transmission organizations (RTOs), and other transmission organizations—are involved in running the grid today. At the federal level, the Federal Energy Regulatory Commission (FERC) has regulatory authority over interstate sale of electricity and the operation of regional markets. The North American Electric Reliability Corporation (NERC) has the responsibility, under FERC authority, for power system reliability, operating, and planning standards in the United States, and coordinates with Canada. Every utility in the United States and Canada participates in the NERC reliability assessments to ensure that the transmission system meets standards and will perform reliably. Most criteria for planning of transmission are based on the NERC standards.

22.1 Balancing Authorities

From a system perspective, the balancing authority[6] is the critical management element. As defined by NERC, the balancing authority (formerly called control area) is the responsible entity for ensuring the electrical balance between load and generation; the balancing authority maintains frequency and ties to neighboring balancing authorities. Within the balancing authority's area, generation schedules are established to meet the changing demand. Deviations from this balance result in changes to system frequency and net imports from, or exports to, neighboring balancing authorities. Generally, these imports and exports are scheduled in advance, but deviations from the schedule are common, with limitations on how often these deviations can occur and persist.

22.2 Regional Entities

Eight regional entities provide a mechanism to address the differences across the regions in North America (see Figure 22-1). NERC works with the regional entities to improve the reliability of the bulk power system while acknowledging the differences between regions. Membership of the regional entities comes from all segments of the electric industry and accounts for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

[5] The reason that back-to-back HVDC ties are used rather than simpler AC connections is a consequence of some rather technical aspects of the operation of large AC power systems as well as certain aspects of the history of development of transmission.

[6] According to NERC (n.d.), the balancing authority is, "[o]ne of the regional functions contributing to the reliable planning and operation of the bulk power system. The Balancing Authority integrates resource plans ahead of time, and maintains in real time the balance of electricity resources and electricity demand."

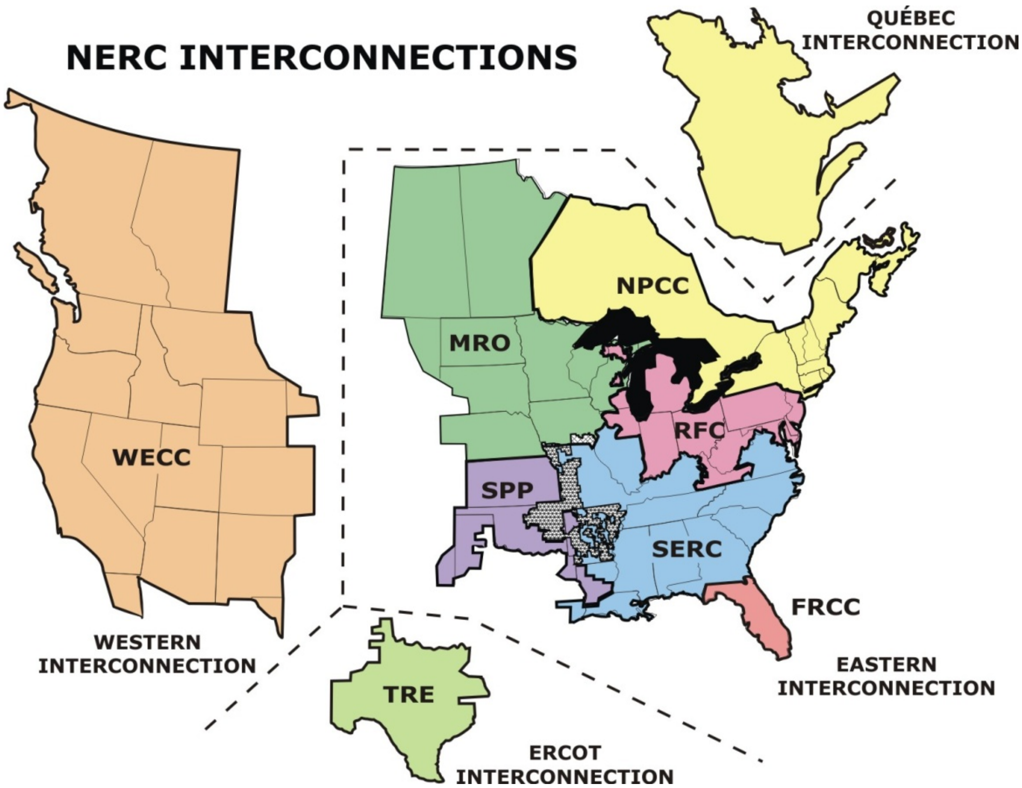

Figure 22-1. North American Electric Reliability Corporation synchronous interconnections and regional entities

Eastern Interconnection:	FRCC = Florida Reliability Coordinating Council
	MRO = Midwest Reliability Organization
	NPCC = Northeast Power Coordinating Council
	RFC = Reliability First Corporation (PJM)
	SERC = Southeastern Electric Reliability Council
	SPP = Southwest Power Pool
Western Interconnection:	WECC = Western Electricity Coordinating Council
Texas Interconnection:	TRE = Texas Regional Entity or ERCOT (Electric Reliability Council of Texas)

Source: NERC

22.3 Utilities and Power Pools

From the approval of the Federal Power Act in 1935 to the start of restructuring following enactment of the Energy Policy Act of 1992, the grid was designed to provide reliable electric power at minimum costs to customers and was regulated to ensure "just and reasonable" rates. The dominant business model for U.S. electric power during this period was that of a vertically integrated, investor-owned, and state-regulated local utility monopoly.[7] In addition to the investor-owned utilities, there were (and still are) federal, state, and municipal utilities, and rural cooperatives, totaling more than 3,000 load-serving entities. In a few regions—Pennsylvania, New Jersey, and Maryland (PJM); New England; and New York—utilities are organized into power pools to share savings through cooperation with neighbors. In general, utilities that controlled generation also owned and operated the transmission systems. Local utility companies and their customers benefited from the economic exchange of electric energy in power pools across regional networks.

22.4 ISOs, RTOs, and other Transmission Organizations

The Energy Policy Act of 1992 mandated open access to the transmission system. Further access to the transmission system resulted from FERC Orders 888/889 with the creation of ISOs and subsequently in Order 2000 with the creation of RTOs to satisfy the requirement of providing non-discriminatory access to the transmission system. With Order No. 2000, FERC encouraged the voluntary formation of RTOs to operate the transmission grid on a regional basis throughout the United States. Order No. 2000 delineated 12 characteristics and functions that an entity must satisfy to become an RTO (Figure 22-2). In the Eastern Interconnection, the development of RTOs and organized wholesale power markets has transferred a large part of the resource procurement function from states to FERC jurisdiction. The operation and responsibilities of ISOs and RTOs are very similar.[8]

Regions without ISOs and RTOs (such as the Pacific Northwest and the majority of Southeastern states) must conform to FERC's open access mandate; the power exchange among utilities is mostly facilitated through bilateral contracts and power purchase agreements that limit the scope of market between buyers and sellers.

[7] Vertically integrated, investor-owned utilities accounted for nearly 80% of generated electricity as of 2000.
[8] According to FERC (n.d.), the designation of "Independent System Operators grew out of Orders Nos. 888/889 where the Commission suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada). Order No. 2000 delineated twelve characteristics and functions that an entity must satisfy in order to become a Regional Transmission Organization."

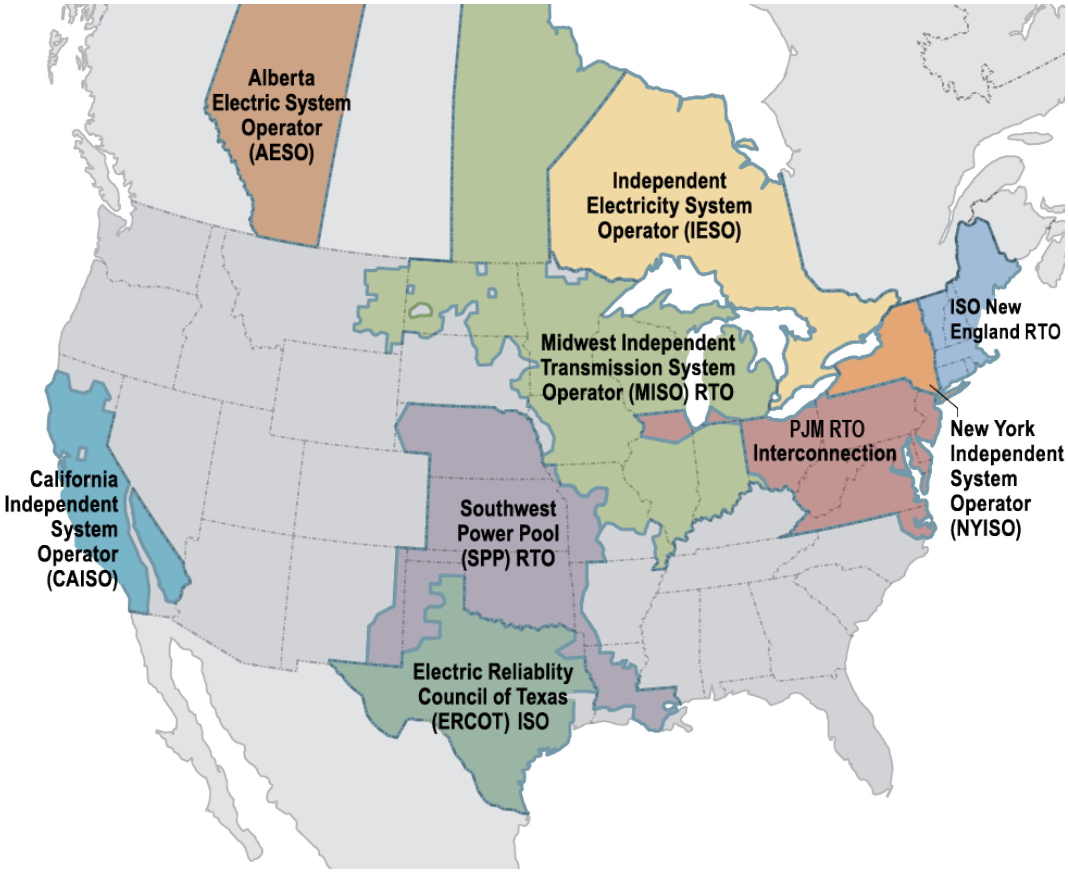

Figure 22-2. Independent system operators and regional transmission organizations of North America

Source: Energy Velocity

In addition to ISOs and RTOs, there are three other types of "transmission organizations" in the United States:

- Traditional utilities that participate in ISOs/RTOs can also consist of utilities from one or several states, and can have planning processes and market functions that incorporate the RTO footprint
- Traditional utilities that do not participate in an RTO, and have their own regional planning
- Merchant transmission organizations that plan transmission and seek participants to help fund the transmission project.

The treatment of balancing authorities, regional entities, utilities and power pools, transmission organizations, interconnections, and other such aspects of the U.S. grid within RE Futures is described in Chapter 28.

Chapter 23. Utility System Planning

Utility system planning is a complex process that starts with projection or forecasting of demand for electricity and develops alternative scenarios for the adequacy of generation resources and necessary transmission and distribution system additions. This endeavor is especially complex because the lives of the components and subsystems often exceed 40 years.

The roles and responsibilities for planning the future grid have evolved over the decades, and they continue to change. Prior to industry restructuring in the 1990s, planning for future infrastructure investments was largely in the hands of the vertically integrated, investor-owned utilities that planned both generation and the delivery system with cooperation among neighbors through the then-existing power pools or the large federal utility entities in the West and the Tennessee Valley Authority in the East (Stoll 1989, Balu et al. 1991).

The Energy Policy Act of 1992 (EPACT 1992) required open access to transmission and created a new class of generators called exempt wholesale generators. Behind these changes was the intent to open competition in the electricity sector and permit wholesale customers to buy in a competitive open market. FERC Orders 888 and 889 issued in 1996 started the regulatory implementation of the EPACT 1992, and significant restructuring of the industry resulted. Order 888 fundamentally changed the dominant business model of the investor-owned utility industry by unbundling transmission services from the sale or marketing of electricity.

With these changes, the integrated utility planning process was fundamentally changed. The following decade saw a significant decline in transmission investment Orders 888 and 889 created challenges to coordination of transmission and generation planning. Coordinated planning of transmission expansion and generation was the standard within the vertically integrated utility prior to restructuring, and was generally precluded by Order 888 as a consequence of the resulting separation of transmission from generation in many regions (Hirst and Kirby 2001).

The Energy Policy Act of 1992 and the diverse industry response across the various regions within the United States increased the diversity and complexity of utility planning. Where wholesale markets and independent power producers are significant, the responsibility for transmission planning largely rests with the RTO/ISO as does the procurement of generation resources. Where vertically integrated utilities continue, the process is still more complicated due to the existence of exempt wholesale generators, open transmission access, and the FERC orders.

Using funds from the American Recovery and Reinvestment Act of 2009 (Recovery Act), the U.S. Department of Energy has initiated coordinated, interconnection-wide transmission planning, with broad stakeholder input, and processes to feed these transmission plans back into decision-making at all levels (Funding Opportunity Announcement, FOA #68).[9] This interconnection-wide planning activity is meant to facilitate development of robust transmission

[9] The America Recovery and Reinvestment Act of 2009 directed the U.S. Department of Energy to provide assistance for the development of interconnection-wide transmission plans for the Eastern and Western Interconnections, and for Texas (ERCOT).

networks that can enable the use of new, clean energy generation and address the weaknesses that exist in the grid.

In 2011, FERC issued Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, a continuation of Orders 888 and 890. This new order contains guiding language regarding how transmission planning cost allocation should occur.[10] This order is expected to result in greater emphasis on coordination of generation and transmission planning and more cooperation among neighboring utilities.

A well-planned regional or interregional transmission system has many economic and reliability benefits, which include but are not limited to improving load diversity, providing access to lower-cost remote generation, diversifying the resources portfolio (capacity and energy), sharing of resources and reserves among neighbors, enabling development of new resources and their integration, mitigating market power, and reducing price volatility. Reliability benefits include reduction of outages from multiple system contingencies and sharing of reserves, both of which also provide economic benefits. Transmission provides these benefits while accounting for less than 10% of the final delivered cost of electricity [total electricity retail sales revenue was $372 billion in 2011 (EIA n.d.)]. In general, three transmission expansion-planning approaches are in use:

1. Plan incremental transmission and generation additions to ensure system reliability
2. Plan incremental transmission and generation additions to ensure reliability and relieve system congestion or constraints and improve economics
3. Plan a transmission "overlay" that would realize the broad benefits discussed in addition to allowing remote resources to reach all energy markets—without adversely affecting underlying AC transmission systems through appropriate upgrades.

The first two approaches generally look out 10 years or fewer. Many transmission organizations refer to their 10-year plans as "long-term" and adjust these "long-term" plans with "near- or short-term" plans to account for recent system changes. These plans typically study incremental transmission additions, new generation, and load growth projections to address reliability and, in some cases, how to mitigate transmission system constraints and allow more economic operation.[11] The adoption of the third approach, which generally looks out 15 years to more than 20 years, is a recent trend among utilities in transmission planning and signals a return to the longer-term planning that was common before restructuring. The benefit of this approach is that long-term needs of the transmission system, in terms of capacity and corridor requirements, can be identified by analyzing various scenarios and identifying common transmission needs in a proactive approach. This information can then be used in subsequent feasibility and detailed system studies that address reliability concerns, transmission system constraints, access to lowest-cost generation resources, and impacts to underlying systems. A combination of these three approaches is best employed to address the particular needs of the system being studied. A bottoms-up approach can address short-term reliability and constraint mitigation needs, and a

[10] For the complete Order 1000 text, see http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.
[11] Constraints (also referred to as *congestion*) are a condition of the transmission system in which the transmission line loading has met the operating limit criteria for which it was designed. It is a problem to the extent that lower-cost resources are prevented from reaching higher-priced markets.

top-down, "value-based"[12]approach might best address the system's long-term reliability and economic needs.

Short-term studies may work well in some applications, but they may not adequately identify the longer-term (20-year and beyond) needs of the transmission system. Reliance on the short-term approach may lead to sub-optimization of the bulk electric system over time (e.g., inadequate transmission capacity and voltage selected). For example, in the short term, a lower-voltage and less expensive line addition may be adequate but may require an expensive upgrade within a decade; in contrast, an initially more expensive and higher-capacity line might be less expensive in the long term. Short study periods and their potential sub-optimization—given the 40–60-year (or more, in many cases) in-service life of transmission lines—may limit the possibility of constructing higher-efficiency multiple-line systems and identifying underlying system upgrades to fully realize the reliability and economic benefits a robust transmission system provides.

As states and federal agencies work to implement new energy policies, the process of utility planning will continue to change and evolve. New and emerging technologies discussed in Section 26.1 offer new technical solutions, and new institutional arrangements may facilitate their adoption. Barriers to institutional innovation may also bar adoption of new technological solutions. The cooperation being promoted by the interconnection-wide planning activities of the Recovery Act as well as the new FERC Order 1000 may be critical elements to utility planning.

[12] A value-based approach seeks to quantify the cost of outages and balance it with the cost of infrastructure to avoid or minimize the costs of outages to customers. [13] All planning must meet NERC standards as shown on its website at http://www.nerc.com/page.php?cid=2|20.

Chapter 24. Grid Reliability

As discussed in Chapter 22, electricity production and demand must be dynamically balanced at all times. Achieving this balance is a challenge for the planning,[13] engineering, and operation of the power systems because of variability and uncertainty of load and unexpected equipment failures that affect the generation and delivery of electricity. Maintaining this dynamic balance and the significant consequences of failure to do so is a fundamental challenge. Many elements contribute to the operability of an electric power system at many scales, from purely local to regional. Local reliability issues can range from a small electrical disturbance that lasts from a fraction of a second to a few minutes, or a more extended interruption of electric supply as a consequence of a local event such as a tree falling across a power line a few blocks away due to severe weather. The consequences can range from a loss of power quality to an outage that can last from hours to days.

NERC defines electric system reliability as "the ability to meet the electricity needs of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available electricity (NERC n.d.)." Maintaining reliability involves ensuring that adequate resources are available to provide customers with a continuous supply of electricity as well as having the ability to withstand sudden, unexpected disturbances to the electric system (NERC n.d.). NERC describes power system reliability more completely in terms of electric system adequacy and security.

- *Adequacy* is "the ability of an electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably[14] expected unscheduled outages of system elements" (NERC n.d.).
- *System security* or *operating reliability* is "the ability of an electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of power system element(s)" such as a power plant or a transmission line (NERC n.d.).

The *stability* of the grid is the ability of an electric power system to maintain a state of equilibrium between generation and demand during normal and abnormal conditions or disturbances. If the system becomes "unstable," it may experience a "collapse" of system voltage and, as a consequence, protective equipment may open circuit breakers and disconnect areas from the interconnection, in hopes of keeping smaller areas within operational limits and subsequently causing the interconnection to break into pieces as it did in the August 2003 blackout.

Power systems are planned and operated so that a credible disturbance, event, equipment failure, or other contingency will not cause any area of an interconnection to be operated outside of specified voltage and frequency and not cause generation or transmission equipment to operate

[13] All planning must meet NERC standards as shown on its website at http://www.nerc.com/page.php?cid=2|20.
[14] The question of what are reasonable contingencies to examine is a very complex one. The complexity increases greatly as the number of simultaneous contingencies increases. If there are N elements in the system, contingencies are referred to as N-1 (Class B), N-2 (Class C and D), etc. Very-large-scale blackouts are often preceded by an N-3 contingency.

outside normal limits. The participants in the grid follow rules and principles to ensure reliability for planning and operating the interconnections; these criteria form the basis for reliability standards (NERC 2012).

A complete analysis of power system reliability comprises the following:

- **System adequacy:** To fully understand overall system adequacy, Monte Carlo simulations are generally required to measure LOLP with the appropriate probability density functions of various power system variables. Many scenarios would need to be analyzed to understand whether the overall electric system has adequate system capacity to meet load under a variety of operating conditions. With conventional generation units, this type of study typically involves running reliability models using the forced outage rate and mean time to repair for the full suite of units, while also considering possible changes in electricity demand, to estimate the LOLP. With high amounts of variable generation, analyses of this type become somewhat more difficult due to the unique behavior of variable generation.
- **High-resolution production modeling:** In most electricity systems today, load changes in somewhat regular patterns from one hour to the next, and within each hour. Load typically increases during the morning period and falls off in the evening. With high levels of variable renewable generation, however, net load[15] may vary more irregularly and on shorter time frames. Running simulations at sub-hourly levels or even at sub-minute levels may be needed to fully understand the impacts of these changes in net load and to assess the quantity of reserves needed to manage variability and forecast errors that occur within the hour.
- **AC analysis:** Many power system models use what is called a direct current (DC) power flow assumption, which approximates how power flows on the system in order to readily solve optimization problems. In practice, this means that the voltage of the system is ignored, reactive power flows on the system are ignored, and line losses are approximated. A full AC analysis can more accurately estimate power flows on the system and address these concerns. In RE Futures, while GridView provided DC power flow analysis, a full AC analysis was not done.
- **Power system stability studies:** *Stability* is a condition of equilibrium between opposing forces, and maintaining power system stability is essential to ensuring a reliable electricity system. *Rotor angle stability* refers to maintaining synchronism between synchronous machines—these are primarily the large-scale power generation units in central station power plants. *Small signal stability* refers to maintaining synchronism following small disturbances, and *transient stability* refers to maintaining synchronism following severe disturbances. A variety of studies are necessary to address these aspects of power system stability, including analyses of synchronism during transmission system faults as well as other studies that evaluate frequency response during loss-of-supply events. As one example of the issues in question, many variable renewable generators cannot currently respond to system-

[15] Net load is calculated by subtracting all forms of variable generation from the native load. The net load is what must be managed by the remainder of the power system, assuming all variable generation can be used when available.

wide frequency deviations with off-the-shelf technology, and analyses are therefore needed to assess (1) future electricity systems where substantial amounts of generation do not have frequency response capabilities as well as (2) new technologies that might be used to manage those possible deficiencies. Voltage stability, meanwhile, refers to maintaining steady and acceptable voltages at all buses (major points of connection) in the system under both normal conditions and following disturbances. Regardless of the specific aspect of system stability under consideration, stability studies require very high time-resolution analysis, usually at the hundredths-of-a-second timescale but for only the first few seconds following disturbances.

- **Contingency analysis:** Power systems are typically designed for high reliability and therefore need to be secure following severe but credible contingency events. Real power systems are operated with various contingencies in mind, and careful consideration is required to determine which contingencies should be monitored and how the system should operate to maintain a stable system following contingency events. Analysis of such issues usually includes determining those contingencies that are most likely based on historical evidence as well as those that are most severe, based on contingency screening. The complexity of contingency analysis generally increases with the dimension (i.e., number of nodes and connecting lines) of the system or region being considered and the number of simultaneous events involved.

In RE Futures, the grid reliability analyses described above have not been done. However, the modeling tools employed in the study required adequate reserves to be available, in some cases based on statistical proxies (see Chapter 28 for more information).

24.1 Planning Reserves (Reserve Margin)

A key step in addressing operating reliability and ensuring system adequacy is determining the needed generation capacity that must be installed to meet future demand. Additional capacity above and beyond the expected peak load is needed so that sufficient resources are available at all times to meet load. This additional margin is called *planning reserves*. Historically, planning reserves have been defined and calculated as a percentage of peak demand (load) and can vary by utility and/or region. Typical traditional values for planning reserve margin range from 12%–15% of annual peak load. Dispatchable generators contribute name-plate capacity toward planning reserves.

After the demand has been forecasted for a given time horizon, generation expansion or related models are used to assess system adequacy (i.e., to determine whether there is sufficient generation to meet the future load). Additional capacity is needed to cover possible generation outages or peak load forecasting error. Because of the stochastic nature of generator outages, robust probabilistic methods are used to assess generation adequacy. Models that calculate loss-of-load probability (LOLP) or related metrics such as loss-of-load expectation (LOLE) can be used to assess the probability that there is insufficient generation to cover loads. A typical LOLE target is that there would only be a shortage for 1 day in 10 years (see Figure 24-1).

The effective load-carrying capability (ELCC) is a measure of the additional load that can be supplied after adding new generation, holding the LOLE constant. The ELCC approach calculates LOLP over all hours of the year (multiple years are recommended). Times of high

LOLP are relatively few and typically occur during peak or near-peak periods. This approach explicitly quantifies and holds constant the risk of having insufficient native generation to cover load. The ELCC approach is robust across all technologies; in particular, it can be applied to both conventional and variable generation technologies.[16] In modern interconnected systems, LOLP and LOLE measure the likelihood that imports will be necessary to meet load during high-risk periods.

Figure 24-1 shows the relationship between LOLE and load. At the presumed target adequacy level of 1 day in 10 years, if new generation is added, the curve shifts to the right. Holding the reliability target constant, the horizontal difference between the curves is the ELCC of the new generator.

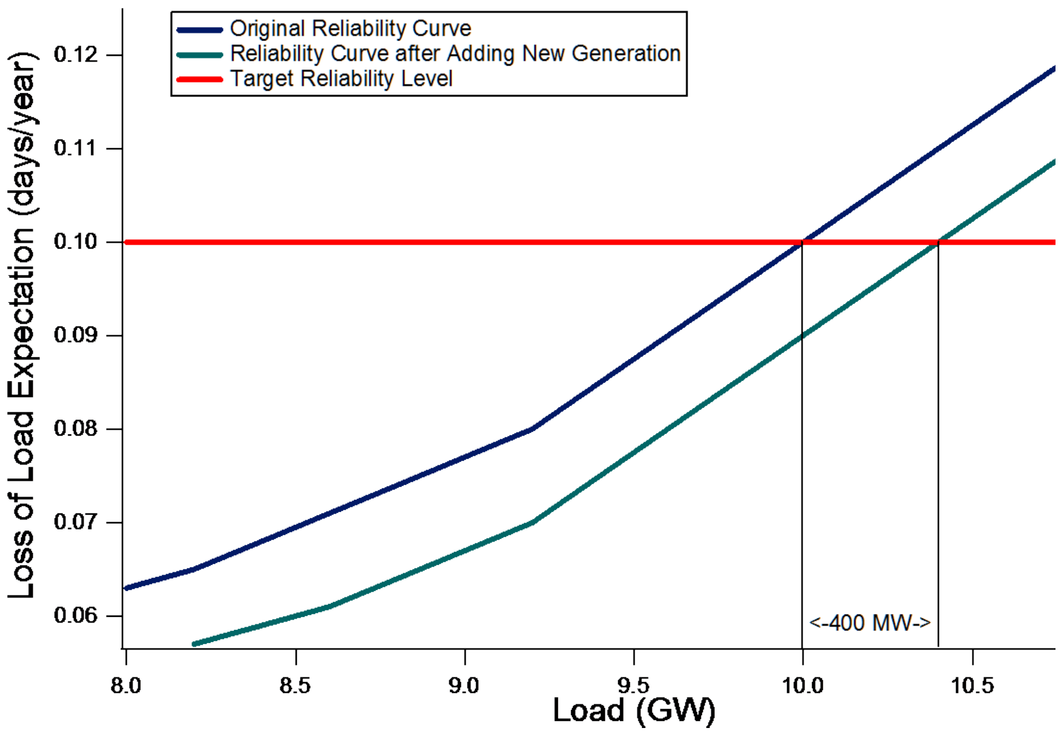

Figure 24-1. Examples of reliability curves to illustrate effective load-carrying capability

Source: Milligan and Porter 2008

[16]The ELCC method is recommended by the IEEE Task Force on Wind Capacity Value (Keane et al. 2011).

Chapter 25. Power System Operations

Power systems operational procedures can generally be divided by timeframe, as depicted in Figure 25-1. A balance between total customer demand and total system generation needs to be maintained essentially instantaneously at all times. The balancing process is carried out in several different time frames. Generating units are typically committed to operation a day in advance to cover the forecasted load profile for that day plus a reserve margin. Scheduling (or economic dispatch) of plant output levels is then carried out generally on an hour-by-hour basis. Some plants are designated to follow load variations within the hour, and other plants provide regulation service to balance instantaneous load variations in the seconds-to-minutes timeframe.

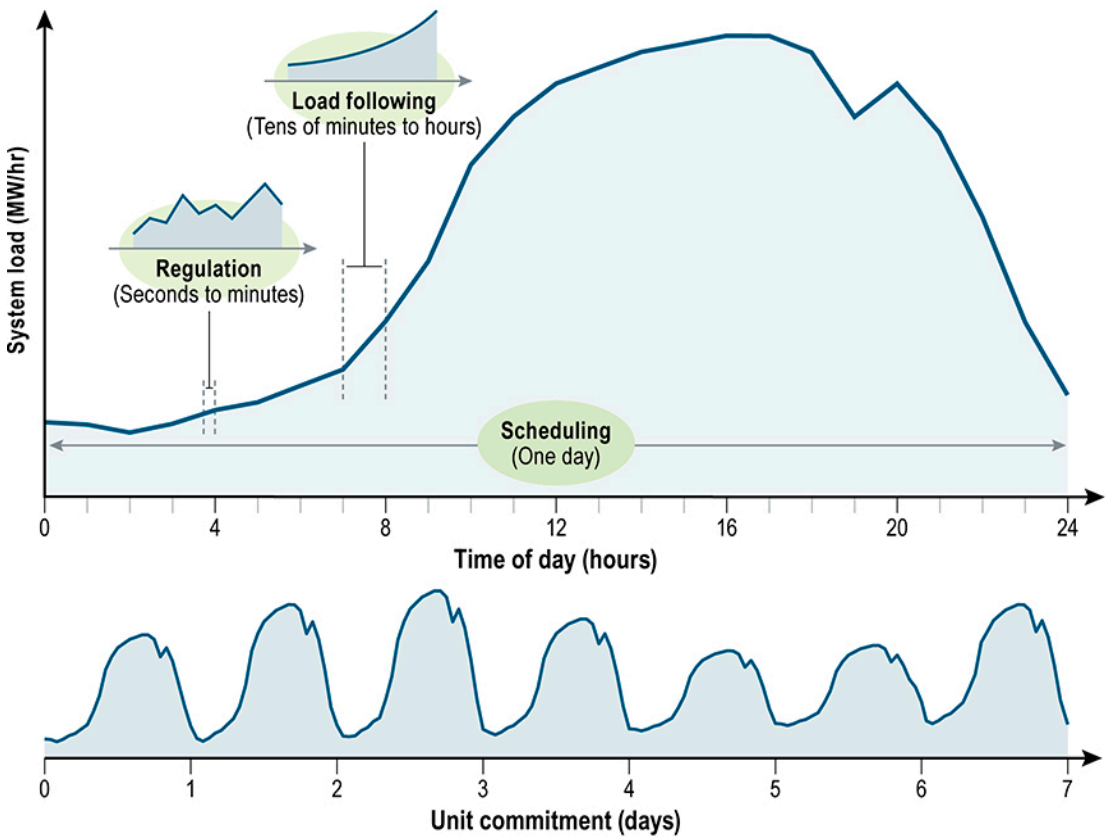

Figure 25-1. Timescales for power system operation

The figure is illustrative and not to scale. The notch at 18–19 hours represents a secondary peak that occurs in some regions in early weekday evenings as commercial load drops off and residential loads ramp up.

This section discusses several elements of power system operations, including forecasting and the day-ahead schedule or unit commitment, within-a-day economic dispatch, frequency response and control, and operating reserves. These functions are initially described in the absence of variable generation. Later sections discuss the impact of large-scale variable generation on each of these operational timeframes.

25.1 Security-Constrained Unit Commitment

Unit commitment is a process of determining which generating units will be needed for the following day, and ensuring that any needed large thermal units are started and synchronized to the grid. This process is based on day-ahead load forecasts, and is necessary because many large thermal units take many hours to reach operating temperature before generating energy. Typical load forecast accuracy depends on many factors, including the size and characteristics of the system itself. Generally, however, a typical error of a day-ahead load forecast is about 2%–3% of the peak load. A typical schedule is planned hourly for the next 24–48 hours, depending on operating practice at the balancing authority. The unit commitment process aims for an economically efficient solution, given the various physical and institutional constraints involved. Because the future is uncertain, there is some risk that either too much or too little capacity is committed, resulting in challenges during the operating day. To help mitigate this risk, the power system operator will commit an additional level of capacity, operating reserves, which can be called upon if load forecasts are in error or if there is an equipment failure. The cost of over-commitment can be significant because some generation may be forced to run at inefficient output levels, or even curtailed. Similarly, the cost of under-commitment can be significant if expensive peaking units must be started to meet load that could have been met by less expensive thermal units. However, the consequences of unit commitment errors vary widely based on system characteristics.

In most electricity markets and utility operator balancing authorities in the United States, the unit commitment process and schedule are generally established once a day, with schedules due mid-day on the day prior to the operating day.

25.1.1 Operating Reserves

Power system operators ensure that there is available generation capability above that which is scheduled for energy, or operating reserves that can respond to the inherent variability in load and unforeseen events such as the sudden failure of a key transmission line or generator. These reserves can be broadly defined as *event-based reserves* or *non-event-based reserves*. A complete discussion is beyond the scope of this report, but details can be found in Ela et al. (2010).[17] When units are committed for day-ahead, sufficient operating reserves must be a part of the determination of the unit commitment stack.

Contingency reserves[18] are used in the event of sudden generator or transmission failure. The balancing authority carries sufficient reserves to cover the loss of the largest contingency, although variations on this are possible. In addition, the proliferation of reserve-sharing groups has allowed sharing of the contingency reserve burden across multiple balancing authorities within the same interconnection, and subject to transmission constraints.

A contingency event occurs very suddenly—within a cycle—when a unit trips or a line opens. Several types of reserve come in to play after the contingency occurs so that the activated reserves can be replaced in case another contingency event occurs.

[17] Milligan et al. 2010 provides an international context for operating reserves.

[18] Contingency reserves are used to balance resources and load and return interconnection frequency to within defined limits following a "reportable disturbance" (a loss of power system element). Contingency reserves can be a mix of spinning, non-spinning, and interruptible load according to requirements established by the balancing authority and reserve-sharing group.

Non-events include the normal operation of the power system. Reserves in this category include *regulating reserve*, a capacity-only service,[19] which is used to manage short-term fluctuations in demand that occur continuously, and *load-following reserve* (Ela et al. 2011), which at present is not a well-defined product but includes an energy component and occurs over time periods from several minutes to a few hours. Reserves can be separated into categories based on required response time. *Fast reserves* generally must be available within 10 minutes, whereas a slower response may be required for load-following or replacement reserves.

The only specific reserve that is required by NERC is contingency reserve; however, the balancing authority's ability to meet its required balancing standards (control-performance standards) results from holding regulating reserves and other balancing reserves. Because these reserves are required in the operating timeframe, they are often referred to as operating reserves, which distinguishes them from planning reserves. There are many variations in terminology regionally and internationally. Some reserve types can be split between spinning (i.e., committed and synchronized) and non-spinning (i.e., capable of connecting and synchronizing within a prescribed time period, typically 10 minutes). Regulating and frequency-control reserves, by their nature, must be entirely spinning, whereas other reserves can consist of a combination of spinning and non-spinning reserve.

If a large thermal generator is suddenly lost, the instantaneous impact of such a loss to the surrounding power system and system operating reserves requirements is depicted in Figure 25-2. Turbine speed governors and the system's automatic generation control (AGC) sense a drop in system frequency and initiate corrective action to increase power from generators that are still operating.

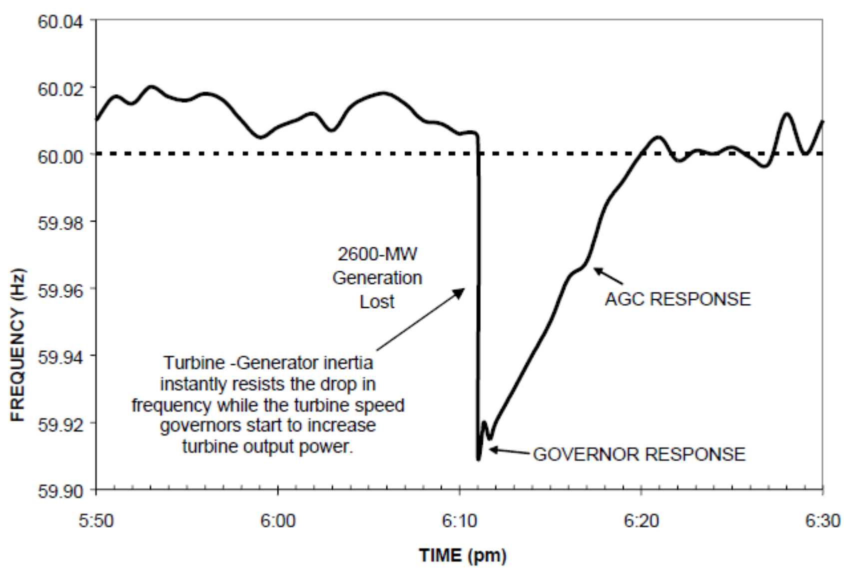

Figure 25-2. Example conventional generator contingency event and response

Source: Ela et al. 2011

[19] A regulating unit sometimes provides energy and sometimes absorbs energy on a second-to-second basis to maintain instantaneous system balance. On average, essentially no energy is provided to the power system by regulating units

25.2 Economic Dispatch and Load Following

During the operating day, in addition to the generation already committed to serving load, the system operator has quick-start generation on reserve to help cover unexpected changes in demand or contingencies and may have access to electricity markets that can provide additional generation. These sources of energy may be used to meet both the anticipated changes in energy demand throughout the day, and any unanticipated changes in demand.

The load-following timeframe generally refers to time steps from tens of minutes to a few hours. Load swings are matched by changing generation schedules. These changes are accomplished by adjusting, or dispatching, generating units to minimize the economic cost of meeting demand, subject to their physical characteristics. This process is called *economic dispatch*.

Regions of the United States that participate in large wholesale energy markets, such as Midwest ISO (MISO) and PJM, typically perform the economic dispatch sub-hourly—in increments of 5 minutes. This means that any generator that is capable of responding—both in its physical and economic capabilities—is available to help manage the variability inherent in the power system. In most regions of the Western Interconnection, the economic dispatch function is performed once an hour. This practice places an artificial restriction on generation that is technically capable of responding to variability; there is no institutional mechanism that allows such units to respond, even if economic.

25.3 Frequency Response and Control

Frequency control (60 Hz) is the basis for several reliability metrics. The deviation of line frequency from its nominal value of 60 Hz is the first indicator of a problem in the power system, and, in general, the larger the deviation, the bigger the problem. The problem typically begins with the sudden failure of a large conventional generating plant or the loss of transmission capacity, resulting in too little power generated and transmitted to fully meet the load. This generally causes the frequency to drop from its 60-Hz value (see Figure 25-2) as large electromechanical generators, motors, and other equipment slow. In correcting this, many factors influence the frequency response and control of the power system. Balancing and frequency control occur over a continuum of time using different resources. Frequency response begins to stabilize the system frequency within the first few seconds following a disturbance. Abnormal frequencies can damage power system equipment, especially large steam turbines. Frequency response from generators actually helps protect the turbines from exposure to abnormal frequencies by limiting the magnitude of the frequency change during events. As more generators participate in frequency response, overall frequency response will increase within the interconnection and the abnormal frequency deviation will be reduced.

Chapter 26. Transmission Technology and Institutional Issues

The design and engineering of the transmission system is affected by both technical and institutional issues—business, regulatory, and political. This chapter provides a brief overview of transmission technology and then an introduction to the basic institutional issues.

Casazza (1993) documents the drivers and benefits of the expansion of transmission systems over the decades and the development of today's interregional grid that spans North America. The value of transmission comes from many sources of savings, such as:

- Delivering electricity from lower-cost remote resources
- Sharing large low-cost generation among systems
- Reducing the need for both planning and operating reserves
- Allowing production of electricity from the lowest-cost supplies at all times
- Taking advantage of seasonal, weekly, and hourly load diversity among systems
- Making remote hydropower and "mine-mouth"[20] coal plants available to more users
- Permitting "surplus" hydropower generation in one system to be used in another.

Today, this list can be expanded to include more economic operation of large regional wholesale markets, access to higher quality, lower-cost remote renewable generation, and reducing variability and uncertainty of variable renewable generation over a large geographical region.

As identified in the National Interest Electric Transmission Corridors and Congestion Study (DOE 2009), there would be general economic benefit from strengthening the transmission system; however, the relationship between this general economic benefit and the private return to companies paying for new transmission is often insufficient or too uncertain to spur investment. New transmission could address the general increase seen in grid congestion and support the creation of broader markets for electricity, as well as support the future integration of renewable resources.

26.1 Transmission Technology

The highest operating voltage transmission lines in the United States, which operate at a nominal 765 kV, came into service in the 1970s. Worldwide, the transmission technologies in use and functioning today, either broadly or in initial installations, for transmitting bulk electrical power are high, extra-high, and ultra-high-voltage AC transmission systems up to 1,000 kV (Global Transmission 2009); high and ultra-high-voltage DC transmission systems; and underground cables (e.g., solid dielectric and gas-insulated). All of these technologies have unique application characteristics, as discussed in the following sections.

This brief overview of basic transmission technology provides a backdrop for understanding the right-of-way requirements for the siting and permitting of transmission lines. The transfer of large amounts of electricity within and among regions can provide economic benefits as

[20] "Mine-mouth" refers to a generating station located at a coal mine in order to be close to the fuel source instead of transporting the coal to the generating facility.

discussed previously, but those benefits can be limited by institutional barriers to expansion of the transmission system. The current motivation for pursuing new higher capacity transmission technology is the growth of large regional markets and the opportunity for greater economic exchange. The future value for this technology may include enabling the transfer of renewable energy from more remote locations, where the higher-quality and lower-cost resources are available to serve load centers, and continuing to support the trend of wider area operational coordination, which can reduce the variability and uncertainty of variable renewable generation.

26.1.1 Alternating Current Transmission Systems

The majority of transmission systems in the United States and worldwide are conventional AC lines. In the United States, these are often referred to as high-voltage (up to 345 kV) and extra-high-voltage (above 345 kV to 765kV). Over the decades since AC technology was first developed, transmission voltages steadily increased as the technology of the grid improved. Higher voltages result in lower losses and higher capacity for a given right-of-way. Higher voltages require greater distances between the wires or conductors as well as better and longer insulators and higher towers, but the net effect is still a significant increase in the power transfer capability for a given width of right-of-way, and higher voltages are preferred for longer distances and larger transfer capacity. Figure 26-2 provides an artist representation of the space requirements for different levels of voltage. Although the highest voltage transmission lines in use in North America are 765-kV AC, transmission voltages continue to increase worldwide.

26.1.2 High-Voltage Direct Current Transmission Systems

High-voltage direct current (HVDC) is occasionally used for very long distance or very high capacity lines. HVDC lines cost less than overhead high-voltage AC lines of the same voltage and have lower operating losses. However, HVDC convertor stations, located at each terminal of the line, cost significantly more than AC substations. Figure 26-1 shows the relative cost of extra-high-voltage AC versus 800-kV DC for constructing a transmission line to transmit 6,000 MW over various distances at 75% utilization.[21] In general, the 765-kV AC, 500-kV HVDC, and 800-kV HVDC systems appear to be the best options. These general performance indicators are subject to project-specific requirements. When performing transmission system expansion planning studies, these project-specific requirements—specifically distance and loading—would be analyzed to determine the optimal transmission technology to meet the project need.

[21] Transmission line and substation costs are based on Frontier Line Transmission Subcommittee, Northwest Transmission Assessment Committee (NTAC), and ERCOT Competitive Renewable Energy Zones (CREZ) unit cost data.

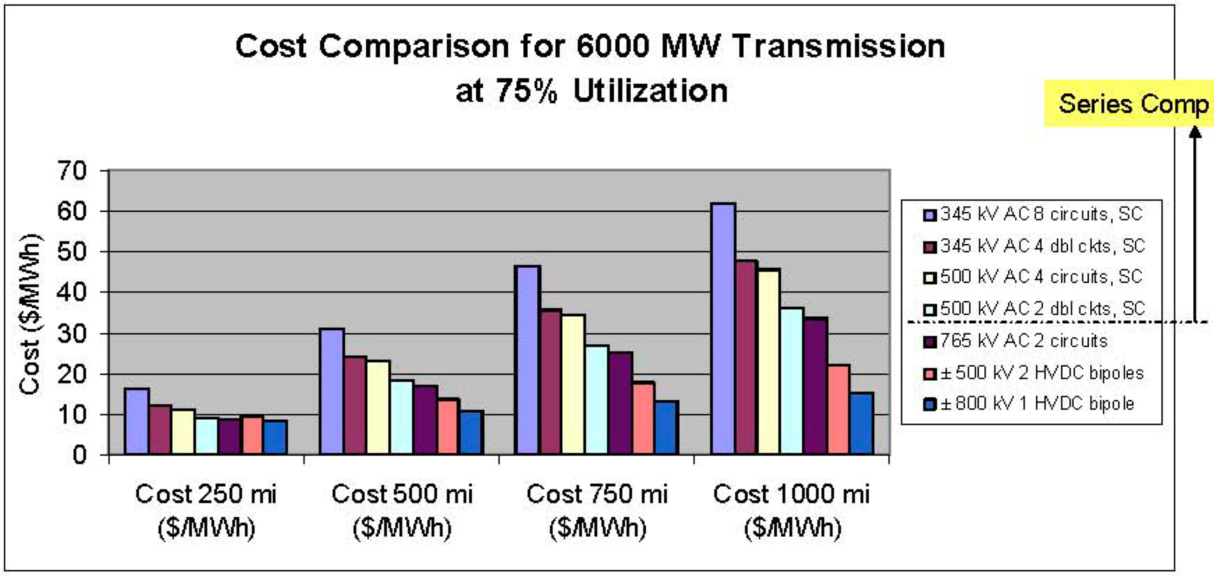

Figure 26-1. Comparison of costs to deliver 6,000 MW over various distances and voltages at 75% utilization

Source: Bahrman 2009

"Series Comp" refers to series compensated AC lines where capacitance is added to balance the inductance of the overhead transmission line as transmission distance increases.

An economic analysis that takes into account capital costs—including converter stations, line lengths, voltage levels, and power transfer capability—would be considered to determine the most economical transmission solution. In general, the break-even point for deciding to use a DC system instead of an AC system for a transmission project (not considering such factors as multiple converter stations and changes in operating voltages over time) is in the vicinity of 300 to 600 miles for overhead lines.

DC transmission systems have significant benefits when transmitting large amounts of power long distances and can do so between two asynchronous AC systems. Additional benefits include, but are not limited to, power flow control and enhanced system stability. For example, the high-capacity contingency rating of an HVDC overlay could accommodate the loss of a large conventional generator and be stable. Regarding land use, DC transmission systems require less right-of-way for similar amounts of transfer capability (see Figure 26-2).

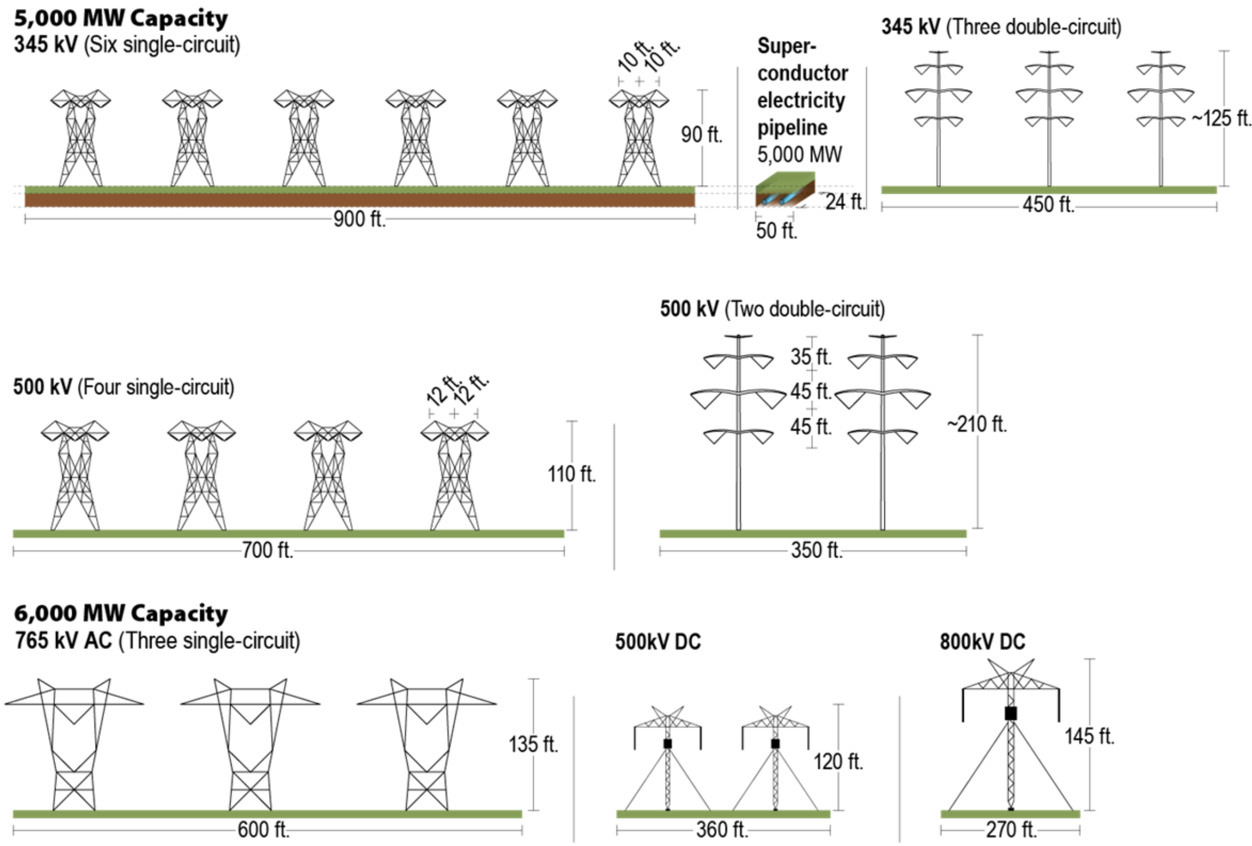

Figure 26-2. Comparison of general right-of-way requirements for various transmission types

Right-of-way is a term that can have different meanings. As used in this volume, it means the path taken by a transmission line and the property impacted by that transmission line. It can also imply an easement or right to reasonable use of the property over which the transmission line runs. The owner of the transmission line may own the property or have an easement or “rights” for its use.

26.1.3 Higher Voltages

Although the highest voltage transmission lines in use in North America are 765-kV AC, transmission voltages continue to increase worldwide.[22] As shown in Table 26-1, both 1,000-kV AC and DC lines are being constructed in China.

Table 26-1. Ongoing Ultra-High-Voltage Projects in China, 2009

Location	Technology	Capacity	Distance
Jindongnan-Nanyang-Jingmen	Ultra-High-Voltage AC, 1,000KV	6,000 MW	654 km
Yunnan-Guangdong	Ultra-High-Voltage DC, ±800KV 12 pulses, bipole	5,000 MW	1,438 km
Xianjiaba-Shanghai	Ultra-High-Voltage DC, ±800KV 12 pulses, bipole	6,400 MW	1,907 km

Source: Li 2009

The advantage of using higher voltages is the decline in per unit costs; the disadvantage is the risk of losing a larger portion of transmission capacity in a single contingency failure. More detailed studies will be needed to conceptualize, design, and evaluate the merits for a high-voltage "overlay."

26.1.4 Superconducting Cables

When long-distance overhead transmission lines approach major population and load centers, the availability of right-of-way for overhead lines can become limited. Similarly, overhead lines may be undesirable in environmentally sensitive areas. Political and institutional issues can completely block construction of an overhead line. New high-temperature, superconductor-based transmission cable technology may offer an alternative in the longer term, not just for short distances in urban areas but also for long-distance transmission (EPRI 2009) where pipe-enclosed DC superconducting transmission cables can either be buried underground or placed in tunnels. These cables use high-temperature superconductor materials instead of copper or aluminum and have substantially higher power handling capabilities at lower voltages than conventional cables. This additional power-carrying capacity allows this technology to address reliability concerns associated with long-term load growth in densely populated urban areas. When operating in DC systems, these cables exhibit zero resistance, hence zero electrical losses; however, there are parasitic refrigeration losses. The commercial competitiveness remains to be fully demonstrated in the market. As this technology is not commercial, it was not included in RE Futures transmission modeling.

Regarding right-of-way, the superconductor electricity pipeline (EPRI 2009) requires little land and it can be buried, which offers potential benefits to siting and security (Reddy 2010).

[22] ABB (n.d.a); ABB (n.d.b); ABB (n.d.c)

26.2 Transmission and Institutional Issues

Institutional issues related to transmission include jurisdictional complexity, permitting, siting and right-of-way acquisition, and cost allocation and cost recovery, among others.[23]

26.2.1 State and Federal Jurisdictions

Although the Federal Power Act puts interstate transmission rates under the jurisdiction of FERC, the regulatory and economic drivers affecting transmission planning are split among the federal government and the states. Retail electricity rates are set locally by state public utility commissions, cities (in the case of municipally owned utilities), or customer-elected boards (in the case of rural electric cooperatives). The cost of new generation (such as that from a new thermal plant, new wind power, or power purchased from merchant generators) is recovered through retail rates.

26.2.2 Siting, Permitting, and Right-of-Way Acquisition

Currently, the siting and permitting of transmission lines is the responsibility of individual states. A line serving utilities in more than one state or one connecting across several states would best be planned, sited, and permitted in a process coordinated across all involved jurisdictions. However, multi-state regulatory coordination is rare and, where federal legislation has not clarified the situation, can be problematic. Authority for regulation of interstate commerce rests with Congress. Currently, federal regulatory authority over interstate transmission lines is limited to those situations where the U.S. Department of Energy has declared a possible corridor as one of national interest, and there is not yet experience with these recent provisions of law, which makes the development of an interstate transmission line higher risk than the development of a line situated completely within one state. State policy may also create a preference for in-state resources, which would require shorter lines from local resources, but may not permit capturing the benefits of integrating generation across a larger geographic area encompassing several states.[24]

A transmission plan may seem to be technically feasible after power flow and production cost modeling, but can be legally or economically infeasible when attempting to select a specific route for a line. Siting issues that commonly delay transmission permitting include opposition by individual landowners or community groups to the location of the facilities; opposition to the exercise of eminent domain for easements across property; concerns over property values; and environmental concerns regarding endangered species and habitat and aesthetics.

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[23] A white paper summarizing issues affecting siting transmission corridors is available from The National Electrical Manufacturers Association at http://www.nema.org/gov/upload/tC_gameboard_verticle.pdf.

[24] "Section 216(a) of the Federal Power Act (created by section 1221(a) of the Energy Policy Act of 2005) directs DOE to identify transmission congestion and constraint problems. In addition, section 216(a) authorizes the Secretary, in his discretion, to designate geographic areas where transmission congestion or constraints adversely affect consumers as National Interest Electric Transmission Corridors (National Corridors). A National Corridor designation itself does not preempt State authority or any State actions. The designation does not constitute a determination that transmission must, or even should, be built; it is not a proposal to build a transmission facility and it does not direct anyone to make a proposal to build additional transmission facilities. Furthermore, a National Corridor is not a siting decision, nor does it dictate the route of a proposed transmission project. The National Corridor designation serves to spotlight the congestion or constraint problems adversely affecting consumers in the area and under certain circumstances could provide FERC with limited siting authority pursuant to FPA 216(b)" (DOE 2009).

Siting is especially complicated when a major transmission project spans several states. Filing requirements, timelines, and even the type of authority vary by state according to statute. In some states, a single agency conducts centralized ("one-stop") review and approval; in other states, each county conducts its own review and approval. Consequently, a transmission developer may face several litigation actions (each with different issues and evidentiary needs) for one major project.

A state can exercise eminent domain to obtain an easement on behalf of a utility but, in many cases, the utility can obtain landowner consent by offering financial incentives that are slightly more lucrative. However, regulators recognize that having eminent domain as an option generally provides landowners a stronger incentive to accept negotiated compensation because the condemnation value awarded under eminent domain would almost always be less.

The assessment of environmental impacts is an especially common transmission siting issue. In 2008 and 2009, the Western Governors' Association worked with environmental nongovernmental organizations and other stakeholders to identify high-quality wind, solar, and geothermal development areas that had the least impact on sensitive habitats. Although not completed, this work contributed to progress toward the identification of Western Renewable Energy Zones (Western Governors' Association 2009).

Some siting and permitting issues occur at the federal level, particularly when part of a transmission line crosses federally owned land or areas that enjoy protection under federal law. Any proposed development on federal lands requires review under the National Environmental Protection Act, a process that can be lengthy. However, during the past few years, the U.S. Department of Interior has begun to implement programmatic environmental impact statement procedures for wind, solar, geothermal, and transmission projects. This is an effort to streamline the federal permit review by addressing issues that are not site-specific.

The Energy Policy Act of 2005 (EPAct 2005) gave FERC limited "backstop" siting authority. FERC's current authority is limited to national interest electric transmission corridors (also established by EPAct 2005), and recent court rulings have established that FERC's backstop authority only applies if a state siting authority fails to act in a timely manner. The court struck down FERC's ability to overturn a state siting decision that was rendered in a timely manner.

26.2.3 Transmission Cost Allocation

Transmission cost allocation is controversial and one of the most important issues to resolve if significant transmission system expansion is to be realized.

Cost allocation[25] refers to how costs for new transmission are divided among different users and customers. The term implicitly includes discussion of the mechanisms by which costs are recovered. Cost allocation often raises equity issues because customers and regulators in one state may object to paying for benefits that accrue to customers in another state. Most cost-allocation conflicts have occurred over transmission, but they may also include renewable energy integration costs and bulk storage costs in the near future.[26] FERC has ultimate jurisdiction over rates charged for an interstate transmission system within the United States.[27] In states served by a FERC-approved ISO/RTO, most transmission cost-allocation issues are resolved within the rules of the ISO/RTO. FERC Order 1000 contained new guiding language regarding how transmission cost allocation should occur as well as requirements for planning. It is too early to predict the impacts of this order.[28]

[25] In the context of retail electricity rates, *cost allocation* refers to how state regulators allocate a local utility's capital costs among residential, commercial, and industrial customers. This is slightly different from how the term is used with respect to transmission.
[26] For a discussion of cost allocation, see PJM (2010).
[27] ERCOT, which has a footprint entirely within the state of Texas, is under the ratemaking jurisdiction of the Public Utility Commission of Texas, not FERC. http://www.ferc.gov/industries/electric.asp.
[28] For the complete Order 1000 text, see: http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

Chapter 27. Power System Considerations for High Levels of Renewable Generation

There will be many changes in the power system before 2050. Many changes are already underway as new technologies are adopted that improve system operations and economics and as higher levels of renewable generation are deployed. Significant changes in the power system will come from both the demand and supply sides, including both technical and institutional changes.

Likely changes on the demand or load side include vehicle electrification; load-shifting encouragement through time-of-use rates; and increased flexibility in loads driven by utility demand-response programs addressing both load modification and provision of ancillary services. The latter two changes include institutional as well as technical components. Other likely institutional changes include evolution and expansion of markets for energy and ancillary services; evolution of operating strategies to allow wider-area coordination in generation commitment, scheduling and dispatch decisions; and enhanced regional coordination in planning, siting, and permitting new transmission.

Transmission changes driven by technical considerations are likely to include transmission additions to allow enhanced access to remote resources such as wind and solar, as well as expanded cooperation among neighboring balancing authorities; operation at higher AC voltages with broader adoption of flexible AC technologies that increase controllability of AC power flows; new HVDC transmission for long-distance delivery of remote resources; and new underground transmission technologies to address congestion in crowded urban and suburban load centers.

On the supply or generation side, changes are likely to include efficient use of variable-generation forecasting in standard grid operating procedures; generation-fleet additions that are designed with flexible operating characteristics, such as high tolerance to frequent ramping and high part-load efficiencies; modifications to base-load units, if possible, to allow more flexibility, and retirement of some inflexible base-load units; new hydroelectric-generation control practices and capabilities, including changes in hydropower priorities and constraints; and possibly development of new nuclear units with increased operating flexibility.

Utility planners are developing new approaches to planning and operations to successfully manage the challenges of high-penetration variable generation integration and consider how to put renewable generation to the best use (NERC 2009). In addition, a number of recent studies have investigated the impacts and implications of integrating higher levels of wind on the grid. Several of the most significant issues that have been identified and need study are:

- **Planning to meet system capacity and energy needs:**[29] This involves changing from a focus on the capacity to meet the system peak load to planning to meet system energy and capacity needs:
    - Non-dispatchable variable generators, such as wind and photovoltaics (PV), are primarily energy sources rather than capacity sources. They will contribute some capacity value, thus contributing to system planning reserves, but that value will generally be substantially less than the plant nameplate capacity—particularly in the case of wind.
    - This change includes a focus on net load and the correlation between load and the variable supply.
    - Additional attention on estimating the requirement for planning reserves (capacity in excess of peak load) is needed to accommodate the increased uncertainty of a variable supply.[30]
- **Detailed study of variable generation operating impacts:** Studies need to model the magnitude and frequency of changes in load, changes in variable renewable resource production, and the coincident changes in both. Changes across seconds, minutes, and hours will indicate system needs for regulation, load following, and unit commitment. Studies should also test the sensitivity of findings to forecast accuracy.
- **Assurance that sufficient flexibility exists in the generation portfolio:** The additional variability of supply places additional demands on the balance of the generation mix. Higher ramp rates and lower minimum generation levels may be necessary as well as additional regulation capabilities.
- **Upgrading and expanding transmission systems:** Traditional resource planning focuses on the adequacy of generation resources or generation capacity at peak load because resources are almost always more than sufficient at other times. The transmission system must ensure dynamic transfer capacity (i.e., the ability—on an instantaneous basis—to share reserves and average out local variability over large regions, as well as transfer blocks of energy—renewable and conventional energy) is adequate to meet system needs. Decision makers are also considering innovative policies at the state level that would support building transmission to wind resource areas—in some cases, in advance of commitments to build the wind generation capacity. For example, a substantial effort has been undertaken in Texas to identify regions where future wind development is highly likely (called Competitive Renewable Energy Zones or CREZ) and then facilitate transmission additions to access these regions. Through this process, transmission, which takes substantially longer to approve and build than a wind plant, can be in service when or shortly after the new renewable

[29] Traditional resource planning focuses on the adequacy of generation resources or generation capacity at peak load because resources are almost always more than sufficient at other times.
[30] NERC (2009) discusses this issue in considerable detail.

generation comes on line. Similar processes have been initiated in California and other western states.

- **Cooperation in siting and permitting across multiple jurisdictions:** Delivering the most cost-effective renewable energy resources to load centers may require coordination across multiple jurisdictions. Such coordination will require an unprecedented level of cooperation among states and federal agencies that often have conflicting missions and little experience in cooperation.

Within RE Futures, the above issues have been addressed in part within ReEDS and GridView modeling as described in Chapter 28.

The following sections describe the specific challenges posed by variable generation to grid planning and operations, and identify general solutions, or characteristics of solutions, that will be useful in meeting these challenges.

27.1 Technical Challenge of Variable Generation

The renewable resources and technologies assessed in RE Futures analysis include hydropower, geothermal power, biopower, concentrating solar thermal power plants (CSP), wind turbines, and PV, among others. It is important to distinguish variable generation sources from renewable energy sources more generally. Hydropower, geothermal power, biopower, and CSP with sufficient thermal storage are "dispatchable" on a timescale of relevance to power system operations.[31] Wind and PV are not completely dispatchable because if there is no wind or sun, they cannot generate electricity; if there is wind and sun available, their output can, however, be curtailed.[32] In scenarios with high levels of renewable generation, it is the variable generation, mainly from wind and PV, along with the limited flexibility in the remaining fossil and nuclear units, which creates the main technical challenges for the grid.

Variability and uncertainty are different properties of variable generation. For example, even if wind energy could be perfectly predicted, there would be a significant impact on power system operation and planning because wind energy's output changes over the key time and geographic scales for power system operation. This variability implies a need for an increase in regulating capability (unless supplied by the wind plants themselves) and an increase in load following. Other generation resources could be scheduled with certainty; however, the remaining generation fleet would be called upon to meet an increasingly variable net load.

Uncertainty exacerbates these impacts. Because variable generation cannot be forecast with certainty, its variability in key time frames (unit commitment and load following) are partially unknown at the time during which system operational decisions are made concerning plant commitment and dispatch. This implies that operating reserves must be increased to accommodate the uncertainty of variability. Much is known about wind

[31] For RE Futures scenarios in 2050, CSP was generally built with substantial thermal storage, which buffers its output and permits CSP to operate as if it were dispatchable.
[32] Current research into methods for wind-provided regulation, both up and down, is underway.

variability, uncertainty, and integration impacts.[33] Less is known about solar energy variability because of a relative lack of operational solar plant data and few integration studies.

As there is relatively little installed solar capacity in the United States, the characteristics of solar technology (PV and CSP) power output are not well established. It is anticipated that CSP with substantial thermal storage will be dispatchable, offering considerable control of output. Initial experience with PV indicates that output can vary more rapidly than wind unless aggregated over a large footprint. Further, PV installed at the distribution level (e.g., residential and commercial rooftop systems) can create challenges in management of distribution voltage. CSP with storage mitigates both the variability and uncertainty of the output of this technology through the ability to store thermal energy and provide power during periods—6 hours or more depending on the amount of thermal storage and the prior availability of solar energy to charge it—of cloudy weather or at night; further, thermal inertia within the CSP system allows the system to "ride through" short periods (a few minutes) of cloud coverage, such as when individual clouds pass by.

The inability to precisely predict the output of variable generation over various time frames is not unlike what is currently experienced with load forecasting, but the prediction of variable generation delivery is currently more difficult per unit than is load prediction. The ability to predict variable generation output varies among the various renewable technologies and is expected to mature over time, but, as with load, will never be perfect. Both variability and uncertainty increase the power system's need for reserves. Both variability and uncertainty can be reduced through aggregation of generation over larger geographic areas.

27.2 Institutional Challenges of Variable Generation

Institutional challenges can be viewed, in part, as operational, market, or regulatory barriers to economically efficient operation of the bulk power system. These challenges are not new, nor are they unique to the integration of variable generation. As an example, hourly scheduling and dispatch is a well-known institutional constraint to efficient power system operation. Although coordinated or consolidated balancing authorities have enabled sub-hourly scheduling to be largely implemented in the Eastern Interconnection and in Texas, sub-hourly scheduling has not been widely implemented in other parts of the United States.[34] These developments, largely independent of the increases in variable generation on the grid, demonstrate that the increased efficiency of power system operation is a goal worthy of pursuit in and of itself and can drive changes in system operations that will also benefit renewable energy integration.

A significant institutional challenge related to integration of renewable generation is the development of mechanisms that enable the market emergence of flexible technology solutions. More specifically, when such technical solutions have been demonstrated, an institutional framework (e.g., rules and markets) is required that allows the power system

[33] See GE Energy (2010), EWITS (2010), and EnerNex (2006).
[34] For more discussion on activities in the West, see Milligan and Kirby (2010a).

operator to tap the physically available flexibility to help integrate large amounts of variable generation. Each system is different, but fundamental principles that have already been identified in prior integration work on wind energy will apply.

More generally, the U.S. grid operates as a large interconnected system spanning the contiguous United States, Canada, and part of Mexico, yet the governing institutions of the grid do not always interact in the most effective ways. While FERC has regulatory authority over interstate sale of electricity and the operation of regional markets, states have authority over siting and permitting of generation and transmission facilities. This local control over infrastructure has an important impact on new transmission construction and other modifications to the grid. For example, state and regional institutions determine how to allocate costs, subject to FERC orders, which affects the market risks for a range of stakeholders, including project developers. These institutional impacts result in a complex mix of legal issues and political dynamics that impact plans to deploy renewable electricity technologies. Consequently, expanding the use of renewable electricity poses institutional challenges that are often more formidable, and less studied, than the technical challenges.

This brief overview broadly describes some of the institutional challenges associated with high renewable generation futures. Detailed exploration of these issues will require additional study.

27.3 Impact of Variable Generation on Power System Operations

Increasing the amount of variable renewable resources on the grid adds additional supply variations and uncertainty, complicating the task of keeping production matched to load. Given that much more is known about wind generation and its impact on power system operations and flexibility requirements than for other variable resources, the following discussion focuses on that technology; the impacts of other forms of variable generation are expected to be qualitatively similar (Mills and Wiser 2010).

Figure 27-1 illustrates the impact of a high level of wind generation for a particular case. The figure shows that the *net* load, which is what the system operator must manage with conventional units, has a steeper ramp characteristic than the load *alone* does. This implies that the conventional generation fleet will sometimes be required to ramp faster with wind than without it. Figure 27-1 also shows that during low-load and high-wind periods, the net load to be served by the conventional fleet is significantly less than it is in the no-wind case. This implies that, to avoid curtailment,[35] conventional base-load generation must be able to achieve lower turndown levels, or that base-load generation must be replaced by or augmented with more flexible generation technologies over time as the variable generation increases.

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[35] *Curtailment* refers to shutting down a plant or reducing its output at a time when its energy is not needed, or when the transmission system is operating at maximum capacity and thus cannot accept the plant's energy. Substantial incentive exists to limit curtailment of wind and PV plants because their energy is provided at essentially zero operating costs and because the economic justification for these plants generally assumes that all energy available will be sold.

Short-term solutions to the minimum-generation issue include use of out-of-merit[36] dispatch (or more sophisticated dispatch and commitment algorithms that take minimum-generation levels into account), curtailment of wind generation, or increasing exports to neighboring systems.

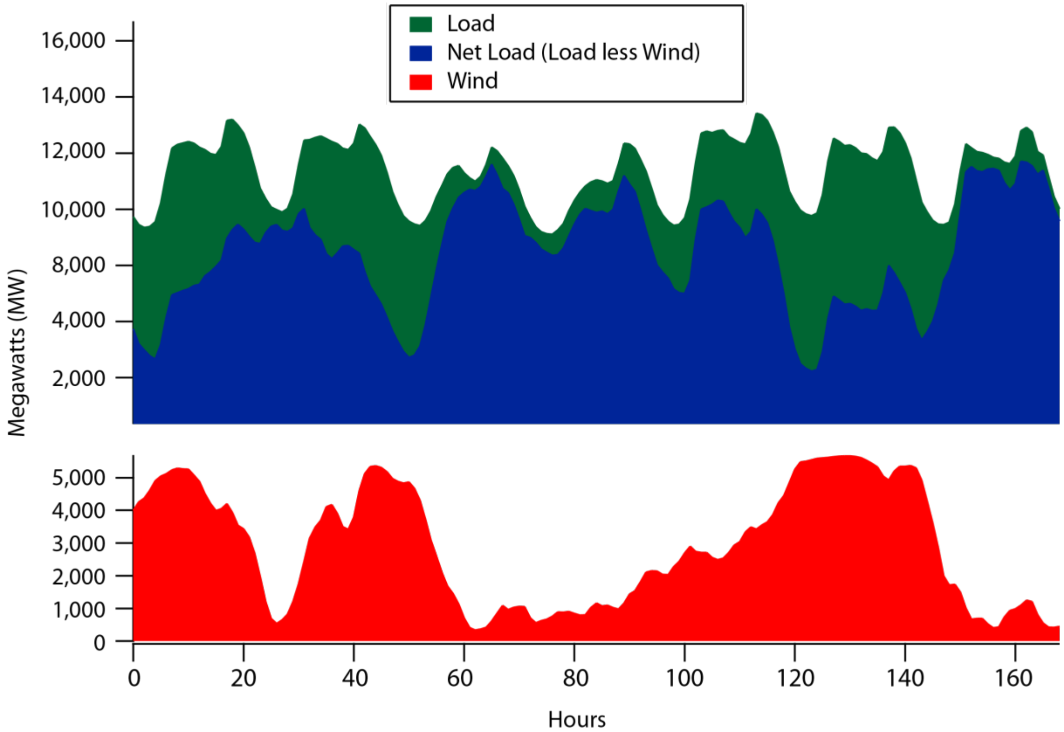

Figure 27-1. Impact of high level of wind generation

Although there is sufficient controllability in modern wind plants to allow for partial or total curtailment, it is not economic to curtail an energy source with near-zero marginal cost and generate power with more costly generation.

Recent analyses have improved the understanding of the impact of high levels of wind generation (e.g., 30%) over broad geographic footprints; however, much remains to be learned. The Eastern Wind Integration and Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS) examined up to 30% wind energy penetration in large portions of the Eastern Interconnection and the Western Interconnection, respectively. In addition, up to 5% solar penetration in the WestConnect region of the Western Interconnection was also studied. Results can be found in Milligan et al. (2009b), EWITS (2010), and GE Energy (2010).

A key finding of WWSIS was that over large footprints, the per-unit variability of wind energy declines significantly. Figure 27-2, taken from WWSIS (GE Energy 2010), shows

[36] *Merit order* is the ordering of generation in order from the lowest marginal cost to the highest. Using a generator "out-of-merit" means it is used out of order of its cost, most often being more expensive than an available generator that cannot be used at the time because of an operating constraint.

two examples of such smoothing. Each graph shows a scatter of the 1-hour changes (deltas) in wind power. The top panels show data for individual transmission zones, whereas the bottom panels show the respective data from larger supersets of the transmission zones. The flattening of the scatter pattern seen in the bottom panels is a powerful indicator of the smoothing impact that can be seen over broad regions. A very high level of variable generation should exhibit similar smoothing over broad geographic footprints. On a per-unit basis, this mitigates variability and uncertainty.

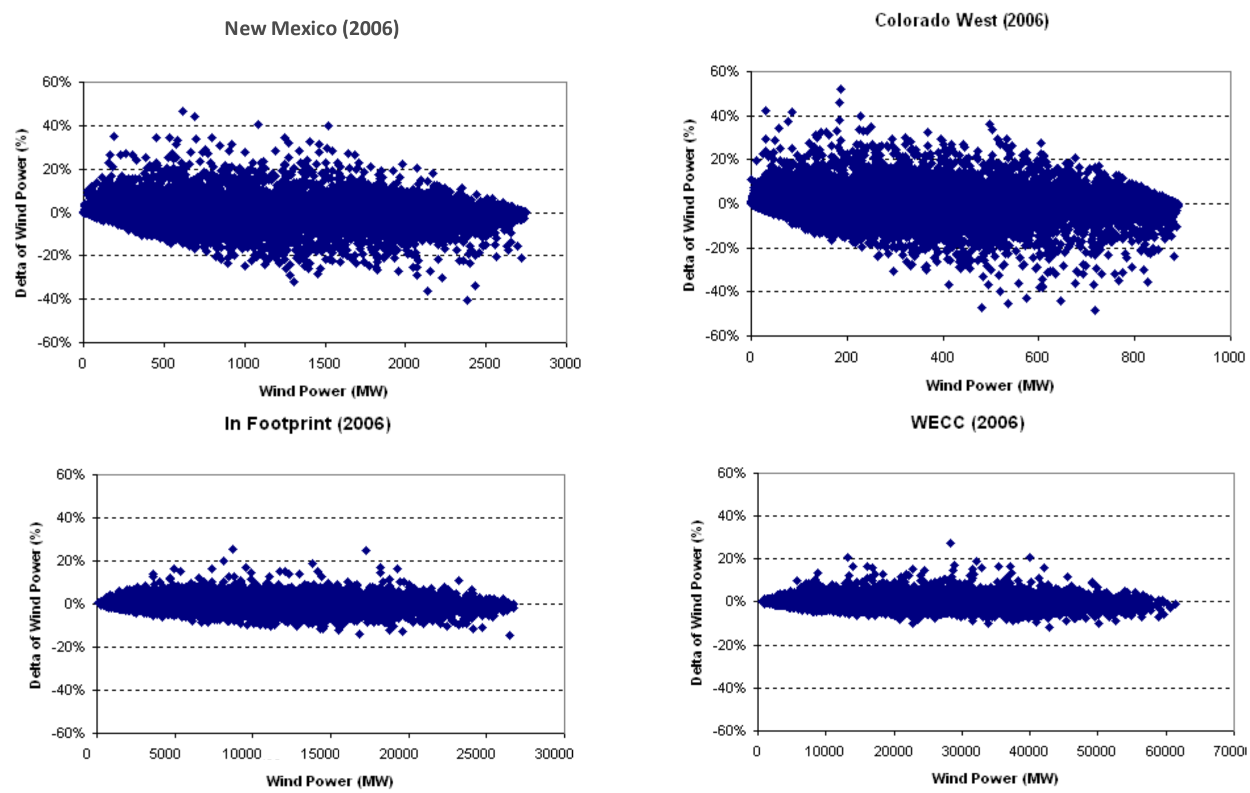

Figure 27-2. Data from Western Wind and Solar Integration Study: Per-unit variability of wind power for four transmission zones

Source: GE Energy 2010

These characteristics are not restricted to the West. Figure 27-3 is based on 10-minute wind power data that were simulated for EWITS. The parabolic shapes each represent alternative collections of wind plants, aggregated up to 85,000 MW of wind capacity. As more wind power is added, the per-unit variability, as indicated by the normalized standard deviation (sigma) of 10-minute wind deltas, declines significantly.

It is clear from these analyses that very high levels of wind (and presumably solar PV) generation will exhibit similar smoothing impacts, helping to alleviate the challenge of achieving system balance.

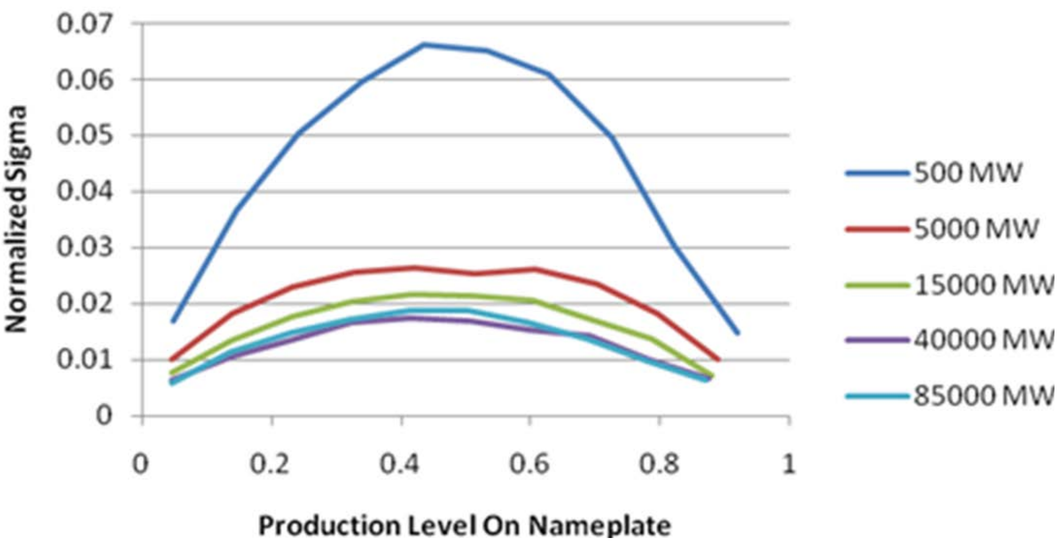

Figure 27-3. Data from Eastern Wind Integration and Transmission Study: Normalized 10-minute variability for five regional groups[37]

Source: EWITS 2010

Large penetrations of variable generation will have significant impacts on how scheduling is optimized to balance generation. Economically efficient unit commitment and dispatch methods have been in use for many decades, and although specific methods to achieve this efficiency may be needed with high levels of variable generation, the target of operating a reliable system economically will continue. Emerging work from large-scale integration studies indicates, however, that the existing resource mix and characteristics may not be optimal for high levels of variable generation. Given a generation mix that is similar to that of today, along with higher levels of wind energy and other variable generation, this work indicates that:

- Base-load generation cycling will increase.

[37] Normalized sigma is the ratio of standard deviation to wind power. It is a measure of normalized variability. A high number denotes more variability than a low number. The graph shows the largest variability is in the mid-range of the wind plant output. Thus, more operating reserve (i.e., flexibility reserve) is needed mid-range than anywhere else. At the upper range, there is no need to carry down reserve because the wind cannot increase. The graph provides an indication of how much, and which direction, reserve is needed.

- More flexibility is needed to throughput the system, from lower minimum operating levels for baseload plants, to faster ramp rates for load following generation, to controlled curtailment of wind and PV.
- The net load that must be supplied from conventional (non-variable generation) generation is significantly different from the reasonably predictable diurnal and seasonal load patterns.

Within RE Futures, the GridView hourly modeling, in particular, examined issues of base-load generation cycling and system flexibility. Because the variations of load and wind tend to be uncorrelated in short timescales (EnerNex 2006), most U.S. analyses (EnerNex 2006; EWITS 2010; GE Energy 2010) have found that only modest amounts of additional regulation are necessary with more wind, with potentially significant impacts on longer time frames that span from tens of minutes to a few hours. The impacts of PV and CSP without storage are expected to be qualitatively similar to wind's impacts, although the impacts may be quantitatively somewhat different, particularly in such cases as fast discrete clouds passing over an area with a high penetration of solar PV on a local feeder. Electric distribution systems and their protection equipment are generally not designed to handle two-directional power flow, so residential and commercial rooftop PV systems may present local integration challenges in some cases.

The remaining discussion in this chapter summarizes the roles of advanced unit commitment scheduling approaches, improved wind and solar forecasting, and potential sources of additional flexibility in the power system evolution to high levels of variable renewable generation.

27.3.1 Advanced Unit Commitment Scheduling

In most locations, unit commitment schedules are currently developed one day in advance. More broadly implementing an approach that updates unit commitment more than once a day, while honoring generation commitment constraints, could improve the efficiency of electricity markets and lower costs. If new information becomes available after a unit commitment decision is made that shows that some generation is not needed (such as by a new net-load forecast that is significantly lower than the one used in the hours-earlier decision), units could be de-committed, according to their economic merit and physical constraints.

Because the unit commitment decision is typically the only binding decision that requires significant lead time (compared to dispatch decisions), advanced methods that can carry out commitment schedules that are robust against alternative scenario realizations have received substantial interest.[38] These stochastic unit commitment methods use alternative characterizations of the operating day, applying probabilistic methods to take these alternatives into account so that the commitment stack can respond to unforeseen variability and uncertainty. If the generation mix is changed to have fewer baseload units and more variable generation, then it will be helpful to reduce the ramp-up times for dispatchable systems (both generation and, potentially, demand response) to contribute to the system flexibility needed to serve net load. The unit commitment challenge may then

[38] See Risoe National Laboratory (2008) for a wind integration study for Ireland that used WilMar's rolling and stochastic unit commitment program.

be less of an issue or could be done closer to real-time with predictions that are more accurate.

27.3.2 Improved Wind and Solar Forecasting

A GE Energy study assessing the potential grid impacts of 10% wind penetration (GE Energy 2005) determined that variable operating cost savings increased from $335 million to $430 million when state-of-the-art wind forecasting was used, with another $25 million in benefits accruing when perfect wind forecasting was used. The Intermittency Analysis Project conducted by GE Energy for the California Energy Commission demonstrated a benefit of $4.37/MWh with state-of-the-art wind forecasting and another $0.95/MWh for perfect wind forecasting (GE Energy 2007). Moreover, it is not only important to implement wind forecasting, but to incorporate it into standard control room operations for scheduling and dispatch decisions. Wind forecasting systems will need to advance to be able to successfully predict large wind ramps, allowing utilities and RTOs to prepare for those events when they occur.

California Independent System Operator implemented the United States' first central wind forecasting system in 2002, and it is now expanding and improving its system. The Electricity Reliability Council of Texas (ERCOT) and the New York ISO (NYISO) implemented central wind forecasting systems in 2008. And, PJM and the Midwest ISO implemented a central wind forecasting system in 2009. In addition, Xcel Energy is collaborating with the National Center for Atmospheric Research and the National Renewable Energy Laboratory (NREL) in developing high-resolution wind forecasts every three hours for wind projects in Colorado, Minnesota, New Mexico, Texas, and Wyoming.

As with load forecasting, wind forecasts of larger aggregations of wind generators are generally more accurate than forecasts for individual plants (see Milligan et al. 2009a and NERC 2010); this will likely also be true for PV and CSP. As discussed earlier, new and improved methods to produce reliable probabilistic forecasts for wind, solar, and load must be developed. This will give operators better information compared to deterministic point forecasts and enable better preparation and better strategies for mitigation of unexpected events.

PV forecasting is not as mature a field as wind forecasting is, and statistics on geographic dispersion are not well developed. However, PV forecasting will likely use a combination of numerical weather prediction models, along with methods that perturbate the clear-skies estimate of solar insolation to simulate and forecast the impact of cloud cover.

27.3.3 Flexibility Needs: Ramping and Minimum Generation Levels

Today's power system has been designed to manage current levels of variability and uncertainty; these are not new challenges. Morning and evening load ramps can be significant, and system operators have established procedures to ensure sufficient ramping capability is available. During the night and other low-load periods, baseload generators can be backed down and intermediate units can either ramp down or possibly cycle off, depending on the technology, generation mix, and load characteristics.

Variable generation adds to the ramping requirements in at least two ways. First, variable generation can increase the ramping requirements already imposed by loads. Even with perfect foresight, ramping requirements for systems with significant amounts of variable generation will increase some of the time. This may be even more pronounced during the high load-ramping periods when wind generation moves in the opposite direction as the load moves. One possible approach to addressing this requirement is for wind to operate in a curtailed mode to address regulation needs and allow dispatchable resources to pick up load. Second, the ramping characteristics of variable generators are typically not as well understood as load, having a more random pattern than the predictable daily load cycle. However, forecasts for large wind ramps are available and will likely be significantly improved. Aggregation also significantly reduces the wind ramping impacts and improves the per-unit forecasting errors.

A significant body of analysis of geographically dispersed wind generation shows that, although there may be times that large unforeseen ramps may pose a challenge to system operations, these ramp events occur over many tens of minutes or a few hours as seen in Figure 27-4. Many different resources could have assisted in the power balance during the slow event. It is likely that solar generation will exhibit similar characteristics; however, short-term changes in PV plant output resulting from variation in cloud cover may prove challenging within small areas and must be analyzed more.

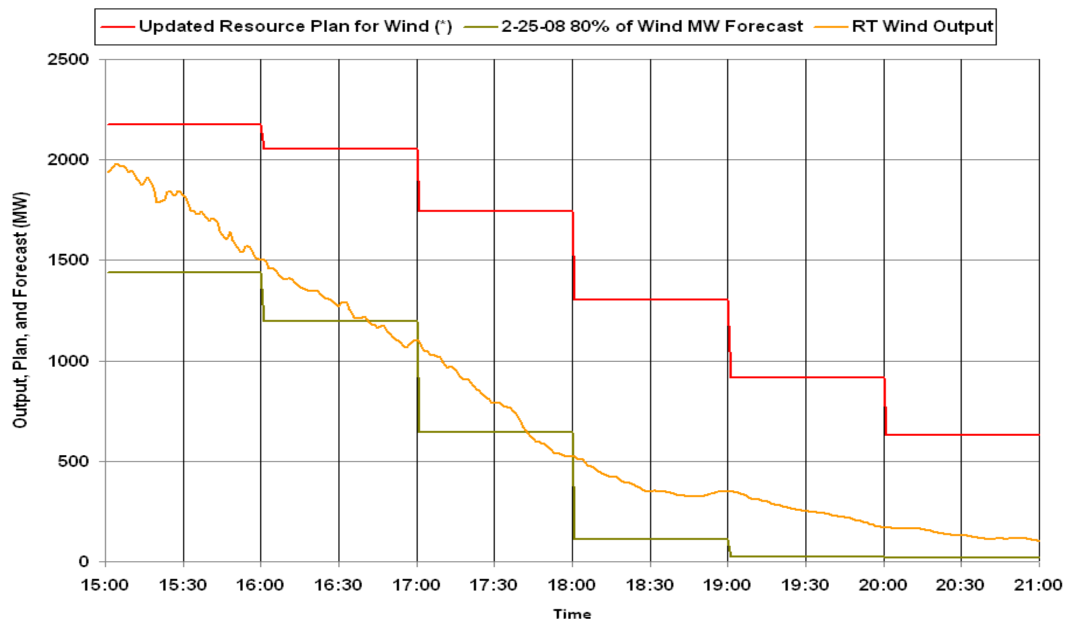

Figure 27-4. Wind ramp event, Electric Reliability Council of Texas, February 26, 2008

Source: Ela et al. 2011

The wind ramp down starts at 3:00 p.m. and continues until approximately 6:30 p.m., giving a 3-hour ramp period. Many different resources could have assisted in the power balance during the slow event. The wind forecast (green) was actually very accurate; however, the updated resource plans were used during this event, exacerbating the wind ramp.

If ramping requirements exceed the capability of the generators to follow the ramps, a separate load-following ramping product might be needed. Figure 27-5 illustrates a simplified example for load alone (Kirby and Milligan 2008a). Extrapolating the example to a case of high variable generation is a straightforward process. Figure 27-5 shows there is sufficient baseload generation to meet the load. However, the baseload unit is not capable of meeting the sharp ramp requirement that begins at 8:00 a.m. Because the baseload unit cannot meet the ramp, a peaking unit is necessary. Had the baseload unit been able to supply the load ramp, the energy price would have been set at $10/MWh, the price of the base unit. However, because the peaking unit has a cost of $90/MWh, in a simple energy-only market, the peaking unit sets the price for the period that the peaking unit is used. Without a ramp product, the energy price will be distorted. In this simplified case, a market for ramping could have paid the peaking unit, but the energy price would not increase to $90/MWh. The development of specific ancillary services markets could address such variable generation-related or other ramp events.

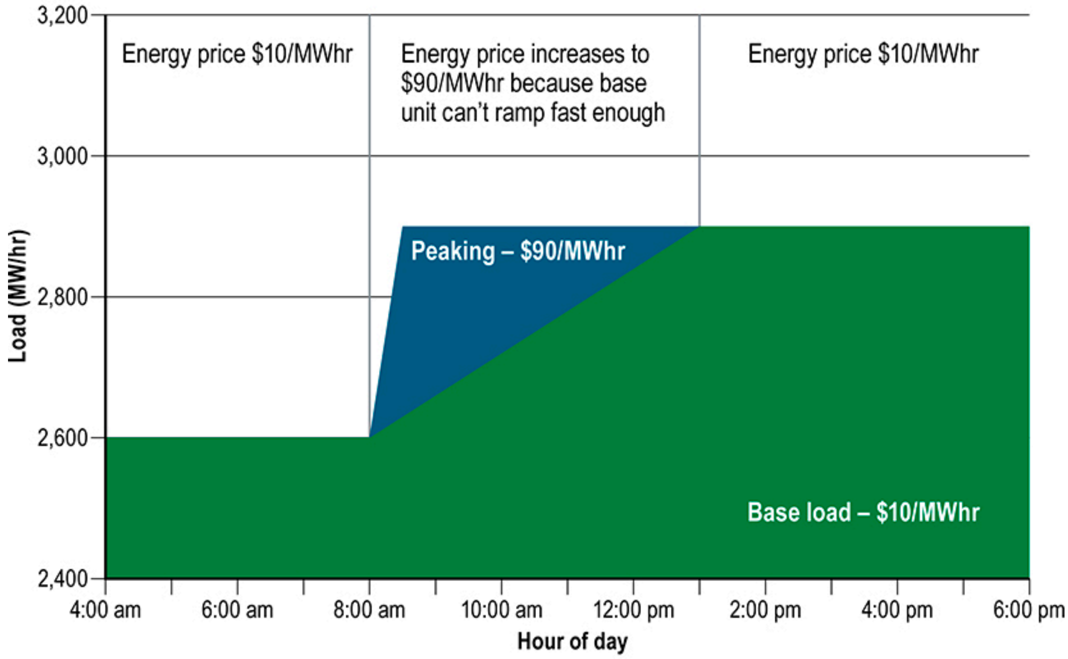

Figure 27-5. Simplified example for load alone

Source: Kirby and Milligan 2008a

27.3.4 Sources of Flexibility

High levels of variable generation clearly require additional grid flexibility, which is the ability to respond to variations in the need for generation. In the context of this discussion, additional flexibility can be obtained by changes to: operational practices and procedures, including scheduling practices; various types of load shifting, demand response, or load management; generation mix and characteristics; market practices; management of balancing authority areas (including through cooperation among balancing authorities); and the use of centralized or decentralized storage. Sources of flexibility can be broadly separated into two categories that are not always clearly delineated: technical sources (e.g., specific types of generation or load technology) and institutional sources (e.g., markets and scheduling practice).

27.3.4.1 Flexible Load

Responsive load includes both technical elements and institutional elements. Responsive loads have the potential to help balance the power system over all timeframes, including sub-cycle stability, minute-to-minute regulation, spinning and non-spinning reserve, peak shaving, and increasing minimum loads. Several types of loads, either under direct utility control or in response to a price signal, can respond to the availability of "surplus" generation, significantly alleviating the minimum load problem at night in systems with high penetrations of wind. In addition to electric vehicle charging, such flexible load may include aluminum production in the industrial sector and pre-cooling of large commercial buildings and storage water heaters. Appropriately designed loads could profitably use wind energy that might otherwise be curtailed while simultaneously providing reserves for that wind generation. An accurate forecast of the amount of energy that might be available seasonally or annually through responsive load is necessary in order to enable industry to design and invest in processes that can take advantage of this low-cost but uncertain resource.

Responsive loads can also include such new approaches as "smart grid;" other automated metering infrastructure; and, in the future, similar but more advanced interactive technologies operating between consumers and producers. The grid and load management potential of these technologies hold promise in the future, such as when coupled with electric vehicles or decentralized or community electrical storage.

Responsive load supplies half of the contingency reserves for ERCOT, the maximum ERCOT currently allows. Providing contingency reserves using responsive loads is attractive in many cases because they are available at lower cost than generation reserves. Typical responsive loads range from residential air conditioning to large industrial loads. Rapid response is often needed, but advances in communications and control technology speed are making this possible. Technology also allows loads to sense changes in the system, enabling autonomous responses to large imbalances between generation and load—as with generators. Price-responsive load, because of the additional system flexibility it provides, is likely to aid substantially in the integration of variable renewable generation. The two examples of price-responsive load below (electric vehicles and industrial load) illustrate the potential benefit.

Electric vehicles may be charged under utility control or in response to a price signal largely at night when surpluses of wind generation contribute to minimum load problems for conventional generators (Markel et al. 2009). This benefits the electric vehicle owners because the energy price will be low. Though electric vehicles will require charging even on nights when there is no wind, the average price for charging energy will be lowered in the presence of high wind generation levels. Perhaps equally important, there will be some flexibility in charging the vehicles. A typical vehicle may require a nightly 20-kWh charge. Though the full charge must be delivered before the morning commute, chargers can be built to allow controlled charging that can be ramped up or down or interrupted to provide fast reserves for wind generation. Even if the wind decreases at night, flexibility in the charging will provide sufficient time for other generation to complete the charge.

Aluminum smelting provides another example of a potentially symbiotic load for high penetration of wind energy. Aluminum production is electricity–intensive, and it is declining in the United States in response to increased electricity prices. Smelters are designed to operate at essentially constant load to maximize their efficiency. Recent efforts have demonstrated the ability of a 400-MW aluminum smelter to provide 20 MW of regulation (Kirby et al. 2009; Todd et al. 2009). It is possible that an aluminum smelter could be designed with greatly increased flexibility to make use of excess nightly wind power, helping alleviate minimum load problems while also providing reserves and regulation, and at a potentially lower electricity price for the smelter. Designing a potline[39] with this much flexibility would be a significant undertaking, but doing so could provide both an economic benefit and a strategic benefit for the United States. An aluminum plant investor would need a solid forecast of long-term energy availability and

[39] A potline is a row of electrolytic cells used in the production of aluminum.

prices to make the investment viable. This potential opportunity was not explicitly included in RE Futures as it was not commercial as of 2010.

27.3.4.2 Flexible Generation

Adding significant quantities of variable generation will increase the variability and uncertainty in the power system. Any conventional generation that is used in a system with significant variability and uncertainty will be more valuable if it is more flexible (i.e., able to respond quickly to changes in variable supply). Adding significant variable generation will increase the current value of flexible contractual obligations. The value of being able to change the output of combined or simple cycle plants has been shown to be a significant portion of the overall value of investing in a new plant, even with the level of flexibility required under existing market conditions (Roques et al. 2008; Bush et al. 2012). For example, a CSP resource with storage is also a potential source of flexible generation that is in service in Spain,[40] and under further development within the United States.[41]

Similarly, increasing physical flexibility can increase the value of new plants as demand for flexibility increases. A perfectly flexible plant is able to run at its full operating point in any interval where the market price exceeds its full-load marginal cost, and to turn off in any interval in which the price is below its marginal cost. Some generators now commercially available have characteristics that approach the ideal of a perfectly flexible unit. Examples include fast starting reciprocating engines and simple cycle gas turbines that can start in 10 minutes or less, and more flexible combined cycle plants with faster start and greater cycling range. (Heikkinen et al. 2008, GE n.d., GE Energy n.d.). Manufacturers are recognizing the need for, and the value of, generator flexibility, and they are offering products to meet that need. These plants can earn more short-run profits in a market than a plant with the same fuel and efficiency level, but less flexibility.[42]

27.3.4.3 Hydropower

Hydropower generation offers the potential to help integrate variable generation resources. Generally, hydropower generation can be divided into run-of–river with limited water storage (output closely follows river flows), controllable hydropower (with a reservoir or pondage), and pumped-storage hydropower (see Chapter 8 [Volume 2] for more information). Run-of-river generation with limited water storage has similar characteristics to wind in some respects: the amount of energy available depends on river flows and there is limited control. Conventional hydropower generation from reservoirs is capable of quick response and provides substantial flexibility needed to help manage variable generation from wind and solar PV.

Water flows are subject to a large number of constraints that honor competing uses of the river. It is not unusual for hydropower generation to be a relatively low priority compared to navigation, flood control, or wildlife management. In addition, hydropower generation

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[40] Andesol Units 1, 2, and 3.
[41] Abengoa Solana, Arizona.
[42] The flexibility of these resources can be limited based on air emissions permits issued with the operational approval of these units. However, air permits might be relaxed if other types of generation (e.g., coal) are decommissioned.

occupies an unusual niche in the power supply portfolio because of its low (marginal) cost but high value to customers with access to this resource. Given the historical allocation of hydropower to specified preference customers and the large body of water law, much of the value potential for using hydropower to integrate large penetrations of variable generation may not be realized without significant changes in the institutions that regulate this part of the power industry.

In large river-based hydropower systems such as the Columbia River system, the parties who receive allocations from the system have coordination agreements with each other. Some experts believe existing, untapped flexibility could potentially be identified by more consistent river-basin analysis and modeling, so that both water and energy needs are fully considered while also honoring other competing uses. The power system's need for fast, short response, for example, may be compatible with environmental constraints that typically have somewhat longer time constants. [43]

27.3.4.4 Energy Storage Technologies

Storage technologies—both the existing large-scale commercial technologies of pumped-storage hydropower and compressed air energy storage, and the emerging technologies of batteries and flywheels—offer significant flexibility in operations with rapid start and ramp capabilities as discussed in Chapter 12 (Volume 2).[44]

High penetration of variable generation may result in curtailment during periods when the amount of available generation exceeds load or exceeds the carrying capacity of the transmission system to deliver to load. Curtailment can also occur when total variable generation throughout the region might require conventional units to operate below their minimum operating capacities. In addition, strategically curtailing some variable generation provides a source of operating reserves, and doing so could reduce the need to retain aged, high-cost, high-emission thermal units (CAISO 2010).

As the amount of "wasted" or dumped generation increases, storage becomes more desirable, if it is cost-effective.[45] Studies suggest that curtailment may be more cost-effective than storage at variable generation levels of 20%–35%, mostly wind (EWITS 2010; GE Energy 2010). While curtailment of renewable generation appears undesirable, using variable generation to charge storage results in round-trip losses of approximately 20%–25% and effectively "curtails" this amount of generation while also incurring the additional cost of the storage system (Denholm et al. 2010a). At very high generation levels, low-cost flexibility options such as demand response and larger balancing authorities may be limited in capability; long-term storage technologies may then be more competitive.

[43] Hydropower in the Northwest has pondage, and it is partially controllable and operates under certain environmental restrictions.
[44] For additional information on storage, see Denholm et al. (2010b).
[45] Levels of variable renewable generation that result in curtailment create an opportunity as the marginal generation is then "wasted" and might be considered "free." If cost-effective energy storage were available, this energy could be saved for use when loads are again in excess of the variable renewable generation.

27.3.4.5 Potential Sources of Institutional Flexibility

Institutional constraints can be reduced or eliminated so that a system operator has the tools that allow access to the physical flexibility that exists on the power system. Examples such as balancing authority consolidation and inter-area coordination, reserve sharing, use of fast markets, storage charging and dispatching protocols, and load and variable generation forecast improvements are notable as areas where substantial improvements may occur in the future. These concepts and their impacts are discussed below.

27.3.4.5.1 New Types of Reserves: Flexibility Reserves

Flexibility reserves refer to scheduling methods and reserve categories, and as such, do not constitute a technological source of flexibility. Considerable work in recent wind integration studies, such as EWITS, has been done to ensure sufficient flexibility is available when needed to manage ramp events. There is no standard definition or term for this system capability, so this discussion uses the term *flexibility reserves*, or reserves that can meet unexpected need for additional system flexibility. In addition to the physical need for flexibility and the operational practices that may need to be changed, certain market implications could also facilitate the development of new reserve types.

27.3.4.5.2 Balancing Authority Area Size and Inter-Balancing Authority Consolidation

Within the last several years, many wind and grid integration studies[46] have found that large balancing authorities are beneficial to integration. This is because the per-unit variability of load and variable generation both decline with aggregation, whereas the capability of the system to manage variability (e.g., ramp capability) increases linearly with aggregation. Therefore, a large balancing authority results in having a deep pool of flexible generation that can respond to variations in variable generation output, helping the system operator maintain balance, and reducing the cost of system balancing. Larger balancing authorities have larger generation pools. Greater flexibility is a function of the generation mix, but larger pools always provide greater flexibility than smaller pools of the same generation mix.

The balancing authority is the basic operating unit within the interconnected power system. As such, the balancing authority has a large impact on power system reliability because it is responsible for maintaining load and generation balance. Increasing the balancing authority size provides economies of scale because aggregating larger amounts of load reduces the effective load variability. Similarly, aggregating larger amounts of variable generation also reduces the effective variability and uncertainty of the generation. The net effect reduces the required regulating reserves. At the same time, the ramping *capability* of the larger balancing authority increases.

Contingency reserves exhibit similar economies of scale. Many balancing authorities join reserve sharing groups to take advantage of these economies. More recently, balancing authorities in the Western Interconnection have been exploring ways to take advantage of the diversity in the variability of their loads and generation with the variability of their

[46] See EWITS (2010), GE Energy (2010), and EnerNex (2006).

neighboring balancing authorities' loads and generation. Advances in communications and control allow sub-hourly trading of energy and ancillary services and virtual consolidation of balancing authorities.

The Midwest ISO (MISO) recently consolidated the operation of 27 balancing authorities, and the Southwest Power Pool is considering moving in the same direction. Even though MISO and PJM have large electrical and geographic footprints, significant seams[47] remain between them, and between New York ISO and ISO New England. In some areas, there is a move towards tighter coordination across operating footprints; for example, New York ISO and Hydro Quebec are moving toward the ability to schedule hydropower transactions sub-hourly, which would significantly increase the flexibility available to both balancing authorities.

To illustrate these benefits, Figure 27-6 shows the hourly ramping that could be eliminated, based on an analysis by Kirby and Milligan (2008b). The teal trace shows the total up-ramp requirements if balancing authorities operate separately, and the dark green trace similarly shows the down-ramping requirements. Because there are many hours when some balancing authorities must ramp up and others must ramp down, netting these movements can save ramping and wear and tear on thermal units. The light green trace shows the net required ramping, and the blue trace shows the bi-directional ramping reduction that can be achieved.

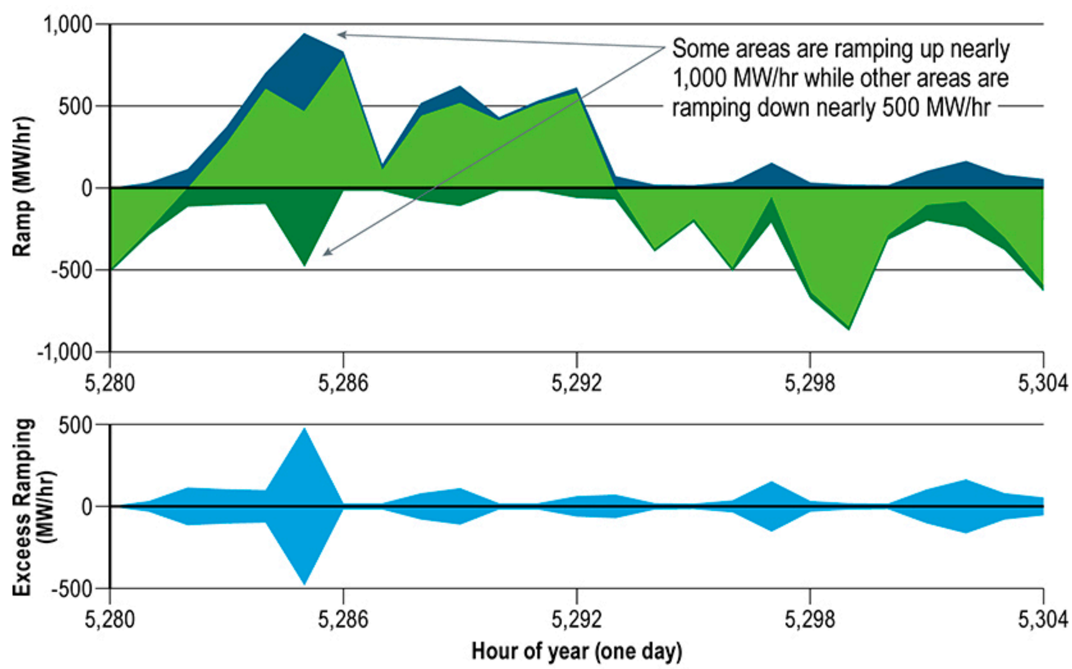

Figure 27-6. Elimination of hourly ramping

Source: Milligan and Kirby 2008b

[47] *Seams* are the boundaries that exist between balancing authorities. Ideally these boundaries would be "seamless" and not limit cooperation between neighbors. Differences in technology and institutions between neighbors create "seams" that can create operating challenges.

Inter-balancing authority coordination is also critical. Fast (5–10-minute) dispatch can improve a balancing authority's ability to integrate variable generation *within* the balancing authority; coordination of schedules *between* balancing authorities can have a similar effect. In a high renewable electricity future, large quantities of variable generation will likely be located in areas that are distant from load centers; in some cases, this distance could span multiple balancing authorities, as currently configured. Ensuring that balancing authorities have the ability to make schedule adjustments several times during the hour will improve the operating efficiency of all the areas involved. Longer term, this coordination can reduce both the amount of installed capacity and types of reserves that are necessary to meet system reliability needs, and export requirements between utilities.[48]

RE Futures modeling and analysis inherently reflects fluid markets. Such markets are assisted through the adoption of sub-hourly energy markets and trading, and sub-hourly generation scheduling across the United States. However, sub-hourly modeling itself was not done in RE Futures, and it is an important issue to be addressed. The modeling and analysis also reflects that voluntary balancing authority coordination would eliminate the technical distinctions associated with balancing authority size. In the absence of actual balancing authority consolidation, it was assumed that inter- balancing authority communication and sub-hourly scheduling effectively accomplishes the same outcome as full consolidation. However, because RE Futures relied on system-wide, least-cost optimizations for capacity expansion and dispatch, markets and trading were not explicitly modeled in the study.

27.3.4.5.3 Future Markets

In the future, market and policy changes will be an aspect of accessing greater flexibility from either new or existing generation units, and might include a combination of expanded ancillary service markets, incentives, and market requirements. In Texas, the GE Energy–ERCOT study made an overarching recommendation that both day-ahead and shorter-term forecasts be used as the basis for ancillary service procurement (GE Energy 2008). With respect to specific services, the study recommended that ERCOT consider introducing a new, non-spinning reserve service with a startup time of 10–15 minutes, representing a new future ancillary service. This service has the potential to reduce the amount of responsive reserves needed for identified periods of risk from reduced wind generation.

Additional market or policy changes may be necessary to better manage large-scale wind ramps, which are relatively infrequent and slow—occurring over several hours—as compared to a sudden generator trip. As such, wind ramps more closely resemble large load ramps than sudden unscheduled generator outages or trips. The ancillary service requirements from large wind ramps are more closely aligned with non-spinning reserves and supplemental operating reserves that are provided by generators and responsive loads that can respond within 10–30 minutes. Current rules may require operators to make available or use very expensive rapid response resources even though wind ramps are

[48] For additional information, see Kirby and Milligan (2009).

slow, and, as noted, limit the response period of reserves to less than the wind ramp period.

Many market-based power system services are priced based on their incremental opportunity costs in the energy market. Energy itself is priced based on the marginal cost of producing it. Suppliers are either profitable or not, based on their ability to recover capital costs from market payments that are based on these relative marginal costs. Ancillary services are priced based on the suppliers' lost opportunity for leaving the energy market to instead supply these services. This system works well and encourages suppliers to bid their actual marginal cost. The system also works well because most suppliers (conventional generators) have significant marginal fuel costs. However, this system for selling energy or ancillary services based on the marginal cost of producing them breaks down when resources with no marginal cost, but non-zero capital costs, dominate the supply of energy or any of the ancillary services. For example, once wind or solar PV systems are installed, there is little or no additional cost to provide power whenever the wind or solar resource is available—the capital cost of these systems has already been sunk. Thus, for high levels of wind or solar PV generation, the marginal cost of power can be near zero over long periods. This situation is in sharp contrast to conventional power systems for which there is always a significant cost for fuel to generate power. Further, for conventional systems, marginal cost pricing can lead to higher prices during periods of peak demand. During peak summer periods when air conditioning demand is high, for example, marginal costs for power may be determined by very expensive gas turbines providing peaking power, and all the generators, low cost coal as well, are then paid for power at the high marginal price for gas turbine power. High levels of renewable generation may turn this cost structure on its head. In this case, during these peak summer periods, the marginal cost of power may instead be set by solar PV, which would be near zero.

Text Box 27-1. Locational Marginal Prices

Locational marginal prices (LMPs) are a method used to set the price of electric energy at a specific location and at the time it is delivered. If the lowest-priced electricity can be delivered to all locations, prices are the same across the entire region and generators are selected or dispatched, in order of lowest to highest offer price or cost (merit order) until demand is met. When there is transmission congestion, energy flow to some locations is limited by physical or reliability constraints. In that case, more expensive energy is dispatched (out of merit order) to meet demand at that location. As a result, the LMP is higher in those locations. The methods for calculating LMPs differ among the markets but they are generally based on a security constrained economic dispatch where the economic dispatch is modified from strict merit order to meet operation, transmission, and reliability constraints.

Wholesale energy markets for electricity use supplier offers and demand bids in an auction environment. Traditionally, regulated utilities use cost-based rather than offer-based economic dispatch for the determination of LMPs. Economic theories suggest that in a competitive market, generators will offer at their incremental costs. Market imperfections and complexities, or the exercise of market power, can subvert economic theory in a system as complex as the grid.

The LMP can then be defined in terms of the incremental generation price (or production cost) to optimally deliver the next increment of energy-to-load at the specified location, or node, while satisfying all the system operating, transmission, and reliability constraints. Specifically, the LMP is the ratio of the cost increment to the energy increment ($/MWh).

More generally, LMP is a method for managing transmission congestion through pricing in a wholesale market for electricity and was originally proposed by Schweppe et al. (1988) and further developed by Hogan (1992). The organized wholesale markets in the United States are operated by the ISO and RTO organizations under FERC oversight. The ISOs/RTOs coordinate the buying, selling, and delivery of wholesale electricity throughput their footprint or region. In their role as system and wholesale market operators, the ISOs/RTOs balance the needs of generators, wholesale customers (generally load-serving entities), and other market participants and monitor market activities to ensure open, fair, and equitable access, all under FERC oversight. The specific methods used by the different markets vary in detail, as described in Litvinov (2010).

In this current marginal cost-based pricing environment, responsive loads,[49] storage, and renewables will likely be "price takers" as long as conventional units are on the margin. During periods when zero-marginal-cost units are on the margin, prices collapse and there is no ability to recover capital costs. Therefore, cost recovery for installed equipment that is based primarily on selling energy at its marginal price would be difficult in such a system where energy prices could be near zero for much of the year—such a market would not be sustainable because the average price would be less than average total cost. As such, high levels of renewable electricity generation may require re-examination of market structures for energy and consideration of a broader range of factors, such as capacity or others, for cost recovery.

Research, particularly on market design, is needed to address this issue. The current LMP market structure was developed during deregulation. This relatively new market may need to evolve to a different market structure to address this issue of near-zero LMPs. A proactive approach to identifying potential market problems could help enable the public and private sectors to construct an appropriate market structure in a pragmatic approach. Potential market solutions include capacity markets or sufficient up-lift for energy prices

[49] For additional information on responsive loads, see Milligan and Kirby (2010b).

so that prices enable capital recovery. Other options are also possible. Ancillary services, such as frequency response, regulation, and ramping must be assured. Although these issues are beyond the scope of RE Futures, an understanding of the operational characteristics of the required system can be informed, in part, by this analysis. Future reforms needed to enable markets to efficiently provide all of the needed physical characteristics for operating the system with high levels of renewable generation can then be explored.

27.4 Impact of Variable Generation on Transmission

For renewables, the tradeoff between nearby, but lower-quality resources, versus distant, but higher-quality resources, with the additional cost of the transmission system, is a particularly important consideration.

The WWSIS and EWITS both developed conceptual transmission overlays to test the viability of increasing the penetration of variable renewable generation in each interconnection. Although no optimization study was performed, both studies concluded that it may often be more economic to build transmission from sites with high-quality renewable resources (or similarly, use nearby, existing lines more efficiently), than to site wind or solar installations in locations with lower-quality resources that are nearer to load. The cost of the additional transmission is often a small fraction of the cost of additional generation equipment at the lower-quality site needed to provide equivalent amounts of electrical energy. Hence, the delivered cost of energy produced at the higher-quality site is lower than the energy cost from the lower-quality site, even though the former requires additional transmission. Neither study—WWSIS nor EWITS—addressed the feasibility of siting and permitting new transmission, nor did they investigate the cost allocation of new transmission.

Exploring the most economic solution to locating renewable generation requires detailed analysis of such issues as reliability, congestion relief, economic tradeoffs of various resource and transmission scenarios, and long-term planning. Building a wind energy plant can be done in 1–2 years, but negotiating the siting and permits for the rights-of-way for transmission that crosses multiple jurisdictions can require a decade. Many detailed alternatives need to be examined, including alternative transmission technologies. Because transmission losses increase with distance and because long transmission lines require reactive compensation, it may be more economical to use HVDC for distances greater than approximately 300–500 miles, as discussed earlier in this chapter. HVDC provides the ability to fully control the power flows and results in lower losses. However, HVDC requires conversion of AC to DC—and back again—and converter stations are relatively expensive. Technology innovation and research could lower the costs of conversion and make DC more attractive. Within RE Futures, HVDC lines were considered for increased capacity for asynchronous interconnects but they were not considered for linking distant renewable generation sources to main transmission lines.

Underground transmission systems could also be used to avoid barriers to siting overhead lines, but the state of the technology, higher costs of "undergrounding," and increased repair time limit its application.

Chapter 28. Modeling of System Expansion and Operations for RE Futures Scenarios

Electric system planners and operators employ a variety of modeling tools, each with a specific temporal and regional focus, to ensure the continuous and reliable delivery of electricity to the customer. These tools include system expansion planning tools, day-ahead unit commitment scheduling tools, hourly economic dispatch models, DC and AC power flow models, and tools for simulation of transient events that occur in seconds as well as market operation models and simulations. Some of these models are continually run and updated as the system or system conditions change. The models used by electric system operators have proven to be very effective; however, they are generally limited to the regional footprint of the system, are focused on near-term operation, and do not include detailed treatment of renewable generation. In other words, a full analysis of the operational and market impacts of all of the high-variable generation penetration scenarios described in Volume 1 is not yet possible, due to the long temporal (40-year) and the large spatial (contiguous United States) scope of RE Futures and the associated uncertainties. However, the modeling tools used in RE Futures address, at a basic level, the major planning and operation aspects introduced in previous chapters of this volume.

The analytic backbone of RE Futures includes two electric sector models: the Regional Energy Deployment Systems (ReEDS) model and the GridView model. ReEDS was used to provide a high level of spatial resolution in order to effectively represent the geographic diversity of renewables and to step through, in 2-year intervals, the evolution of the power system over time. This represents the capacity expansion or planning process described in Chapters 23 and 24. GridView is an hourly chronological production cost model that is used to support and complement the ReEDS analysis. GridView captures some, but not all of the reliability and operational issues described in Chapters 24 and 25. For RE Futures, the generation and transmission capacity as projected in 2050 by ReEDS was imported into GridView, with its hourly resolution, which was then run to provide insights into how an electric system in 2050 might operate. Both models consider the deployment and use of a variety of flexibility options needed to effectively integrate large amounts of variable generation as described in Chapter 27. The following briefly describes how the framework of both models ensures balance between electricity supply and demand. Details of the modeled scenarios, inputs, and results are provided in Volume 1. Additional details on the approaches and assumptions related to the modeling of variable generation are also provided in Volume 1 (Appendix B in particular) and Short et al. (2011)

28.1 The Regional Energy Deployment Systems Model

ReEDS is a generation and transmission capacity expansion model that projects the least-cost evolution, within applied constraints, for the contiguous U.S. electric sector from the present day until 2050 in 2-year steps.[50] ReEDS represents U.S. wind and concentrating solar power resources by dividing the contiguous United States into 356 regions. All other resources and technologies are divided into 134 regions or balancing areas represented in the model. Due to computational constraints driven by the long time horizon and large spatial scope, each model

[50] For example, renewable generation levels in 2050 were prescribed in the RE Futures scenarios. In these scenarios, the renewable generation levels in years before 2050 were linearly increased to meet the 2050 level. ReEDS determined the least-cost renewable generation portfolio along with the least-cost balance of generation.

year is represented by 17 time slices consisting of four time slices in 1 day for each of the four seasons and an additional time slice to represent the summer super-peak demand.

The ReEDS model is highly discretized and consists of multiple spatial hierarchies, including 134 balancing areas (BAs) and 21 reserve-sharing groups (RSGs). Although the existing 133 balancing authorities are considered in the design of the ReEDS BAs, BA boundaries do not correspond with existing balancing authority boundaries.[51] The average generation and demand in each BA is balanced during each of the 17 time slices in the ReEDS optimization routine. For this balance, ReEDS allows transmission of power between neighboring BAs subject to transmission line capacity constraints. In these ways, the ReEDS BAs behave similarly to how existing balancing authorities behave, although there are at least four major exceptions:

1. The dispatch decision in ReEDS is based on a contiguous U.S.-wide, least-cost optimization compared with balancing-authority-specific optimizations, and does not include a separate unit commitment process. It is important to note that regional marginal energy costs (e.g., LMPs) are not used in the capacity expansion and dispatch decision; instead, the full system-wide, 20-year net present value costs of generation resources and transmission additions are used. ReEDS does not represent market behavior in de-regulated power markets, but does find the system-wide optimal solution.
2. The ReEDS model does not represent scheduled and contracted power transfers between BAs and instead simply transmits power on an as-needed basis.
3. The ReEDS model does not calculate reliability metrics specific to each BA, such as frequency-related metrics (e.g., area control error).
4. The balance in generation and demand is based on averages over each of the coarse time slices instead of for each hour.

In addition to balancing generation with demand, ReEDS includes constraints on planning and operating reserves that are satisfied at the RSG level.[52] In other words, ReEDS assumes 21 reserve-sharing groups consisting of the existing ISOs and RTOs (e.g., California Independent System Operator, ERCOT, MISO, PJM, New York ISO, and ISO New England) and assumes consolidations of other regions loosely based on current and future transmission plans.[53] Reserve requirements and curtailment calculations involve statistical calculations to address the inherent variability and uncertainty of some renewable resources (e.g., wind, solar PV) and the unpredictability of demand.

At the longest timescale, a planning reserve (i.e., resource adequacy) requirement is applied in ReEDS to ensure resource adequacy for times of extreme demand.[54] All (conventional and renewable) dispatchable generators are assumed to contribute fully to the planning reserve requirement. However, because variable renewable resources cannot always deliver power on

[51] Political and jurisdictional boundaries, regional resource quality, and demographic distributions are also considered in the makeup of the ReEDS BAs. See Short et al. (2011) for more information.
[52] Electricity curtailment is also calculated for each of the 21 RSGs.
[53] Four RTOs are assumed in the Western Electricity Coordinating Council, one for ERCOT, with the remaining 16 in the Eastern Interconnection.
[54] Specifically, planning reserves are required to exceed the highest forecasted demand by approximately 12.5%–17.2%.

demand, including during times of system stress, their contribution to planning reserves can be considerably less. In ReEDS, a statistical "capacity value"[55] is calculated separately for wind, solar PV, and CSP without storage. This calculation ensures that the LOLP does not increase over time. In addition, as variable generation increases, the capacity value of these resources will tend to decrease due to correlations between the output of nearby wind or solar plants,[56] and because periods of high "net load" for the system (i.e., load minus variable generation) tend to shift to times when variable generation is more limited. In general, the average capacity value of wind and PV drops as renewable electricity penetration increases, both over time and with increasing renewable generation levels. Additionally, when high solar deployment is observed, the capacity value of PV drops significantly as the peak net-load shifts toward the evening hours when PV output is limited or zero. The capacity value of wind, on the other hand, can improve with this shift in peak net-load because wind output is generally higher in the evening than in the afternoon. This also indicates the complementarity of wind and solar resources together.

At hourly to sub-hourly timescales relevant to daily electric system operations, ReEDS requires sufficient flexible supply- and demand-side technologies to satisfy operating reserve requirements. Because ReEDS does not simulate events that occur at these short timescales, operating reserves are only treated on a capacity basis, although the flexibility and ability of resources to meet these operating demands are considered.[57] The operating reserves considered in ReEDS include wind and solar forecast error reserves, contingency reserves, and frequency regulation. Because contingency reserves and frequency regulation requirements are assumed to be established as a fraction of demand (6% for contingency and 1.5% for frequency), they are independent of the amount of variable generation.[58] In contrast, forecast error reserve requirements are estimated based on hourly persistence forecasts for wind and solar PV, and thus increase as variable generation increases. In addition, the different timescales involved in each of the operating reserve types place restrictions on the degree to which each technology can contribute to the reserve requirements. For example, because frequency regulation targets the sub-minute timescales, only generators that are spinning and synchronized to the line frequency can contribute to regulation. Based on existing standards,[59] contingency events must be addressed in roughly 10 minutes with at least half of the reserve requirements to be met by spinning resources and the other half satisfied with non-spinning (also referred to as "quick start") resources. For forecast error reserves, which occur in the roughly hourly timescale,

[55] Capacity value is defined and the different methods for its calculation are found in the IEA Task 25 report (Milligan and Porter 2005).

[56] Wind and solar output are determined by the immediate weather conditions (e.g., wind speed or solar insolation), so the output profiles of proximately located wind (or PV) plants are generally correlated with each other. Having positive correlations within a group of wind (or PV) power plants increases the likelihood that all members of the group will have diminished power outputs simultaneously, thereby decreasing the capacity value of the group. On the other hand, negative correlations, such as those that frequently exist between nearby wind and PV plants, can increase the capacity value of the group as a whole.

[57] For example, start times and ramp rates for conventional fossil energy and nuclear energy plants are used to determine the extent to which a generator can provide spinning and non-spinning reserves.

[58] For many existing reserve-sharing groups, contingency reserves are normally based on the largest single contingency, such as the loss of a large nuclear or coal plant or a large transmission line. Because ReEDS is a linear program and is limited by computational time, the more simplistic treatment of 6% and 1.5% of demand are assumed for contingency and frequency, respectively.

[59] Existing standards differ regionally.

ReEDS simply assumes that five-sixths of the reserve requirement can be met by non-spinning reserves.[60]

Though the above reserve requirements are primarily focused on ensuring a supply-demand balance when unforeseen or uncontrollable events lead to a reduction in electricity generation (or increase in load), the opposite scenario of over-generation is also important, especially from an economic point of view. Because wind and PV are sources of power that are generally not tightly constrained by minimum-output-level or ramp-down restrictions, electricity generation from these plants is likely first to be curtailed in over-generation conditions (e.g., high wind, low demand), and ReEDS estimates the level of that curtailment. Similar to forecast error reserve requirements and capacity values, curtailment is calculated statistically in ReEDS at the 21-RSG regional level. These statistically calculated curtailment values are used in the national investment and dispatch decision in ReEDS. Specifically, the curtailment calculation can be thought of structurally as the opposite of the statistical LOLP calculation (the LOLP calculation accounts for minimum generation requirements of thermal units, the presence or absence of storage, and correlations in output of resources serving each RSG).

28.2 The GridView Model

GridView is a production cost model that simulates the unit commitment and economic dispatch of an electric power system. For RE Futures, the electric power system as modeled by ReEDS for the Low-Demand Baseline and a subset of the core 80% RE scenarios in 2050 was simulated in GridView.[61] A suite of assumptions (as described in Volume 1) was used to import the electric power system infrastructure modeled by ReEDS in aggregate terms into specific units for the production cost modeling. The GridView model captures the same electric system operational aspects as described above in the ReEDS model. However, primarily due to its finer temporal resolution (hourly), GridView is able to capture the additional features described below.

Although GridView is a nodal model with approximately 65,000 buses representing the electric power system, several simplifying assumptions were required in order to match the spatial resolution of the ReEDS model and produce reasonable run times. Demand is balanced at each bus, but transmission constraints are only enforced across interfaces between different ReEDS BAs. This keeps the ReEDS and GridView models consistent and eliminates the need to optimize the placement of every individual renewable generator on the transmission network. GridView considers DC power flow constraints, whereas ReEDS follows a more simplified transportation model.

For RE Futures, GridView balanced operating reserves at the same RSG-level as ReEDS did (as described above). Operating reserve requirements were estimated using the methodology for the Eastern Wind Integration and Transmission Study, described in detail by Ela et al. (2010). Thus, for GridView, this method takes into account the additional frequency regulation that would be

[60] Reserves for forecast errors have not been widely put into practice, and further work is needed to identify the necessary characteristics for reserve providers.

[61] Conversely, walking GridView through time from the present to 2050, as was done for ReEDS, was not possible due to the different nature of the models and due to the computational demands this would have imposed. Thus, ReEDS was used to determine the least-cost evolution of the system under the various high-penetration renewable electricity constraints from the present to 2050 in 2-year steps, while GridView was used to conduct the detailed hourly simulation of the system in 2050 to determine its operation and performance.

required with additional penetration of wind and solar energy (as opposed to the ReEDS treatment where frequency regulation reserves are independent of variable generation penetration), based on the hourly and 10-minute changes of the wind and solar input profiles. GridView enforces constraints for two types of operating reserves: spinning and non-spinning reserves. All variability at frequency regulation timescales (e.g., less than 10 minutes) is required to be online (i.e., spinning). Variability in wind and solar output at timescales between 10 minutes and 1 hour contributes equally to both the spinning and non-spinning reserve requirements. Contingency reserves are assumed to be 6% of demand to match the ReEDS assumptions, and split equally between spinning and non-spinning.

Curtailment in GridView is based solely on minimizing production cost. There is no annual constraint in the hourly commitment and dispatch decisions to require any renewable generation. For details on GridView, see Feng et al. (2002). For more details on and the assumptions for RE Futures, such as application of production tax credits, see Volume 1.

A full reliability assessment of the contiguous United States in 2050 with 80% renewable generation was not attempted due to the detailed regional and local modeling requirements. The ReEDS and GridView models used for RE Futures use simplifying assumptions to balance demand at aggregate and hourly timescales, respectively. Although simplified model constraints have been applied that require RSGs to carry sufficient capacity to respond quickly to contingencies, future work is needed to ensure the full reliability of the electric power system at sub-hourly timescales in high-renewable generation scenarios.

Summary and Conclusions

Today's power system has evolved over the past 130 years from isolated, distributed power plants that serviced local load into three large regionally interconnected systems in the contiguous United States and Canada. Traditionally, the resource adequacy of the system has been based on dispatchable generation under the control of system operators. In addition, with the notable exception of hydroelectric generation, location-constrained resources have not been used. Maintaining balance between demand and generation at all times is a fundamental need. Additionally, system frequency and voltages must be maintained within defined, extremely tight tolerances. Initial studies examining the feasibility of a project are normally followed by more detailed, reliability-focused studies. RE Futures is an initial analysis that requires follow-up studies to analyze in greater detail how the power system will operate to ensure reliability of the bulk power system.

Renewable electricity is available from a very diverse set of resources and technologies. Some are dispatchable, and others—primarily wind and solar PV technologies—are generally non-dispatchable in that system operators can curtail output but cannot increase it if the wind or solar resource is not available. Both wind and solar PV technologies present challenges to power system operators, owing to variability and uncertainty of their generation output on the timescales relevant to the task of maintaining system reliability. However, generation from these variable renewable resources is being added to the electric system now. In particular, wind generation is expanding rapidly in some regions of the United States. As a result, significant operational challenges are emerging, including curtailment resulting from transmission and minimum generation constraints, relatively rare rapid ramps in wind generation resulting from passage of large footprint storm fronts, and increased need for operational reserves due to uncertainty of generation output. Of course, electricity demand also varies and is uncertain, but its behavior is generally well understood based on decades of experience and the developed ability to forecast load with reasonable accuracy a day in advance.

Revised operating procedures and strategies are needed—and are being adopted —to accommodate the characteristics of variable generation. Actual operating experience to date indicates that it is technically feasible to operate an electric power system with wind energy penetrations of 10%–20% of energy generated, albeit with changes in current operational practice to provide increased flexibility and expanded cooperation over longer distances.[62] However, operating challenges are leading to curtailment of wind plant outputs during periods of low system demand or transmission congestion. In addition, in some regions, LMPs for electricity have sometimes fallen to values too low to sustain either variable or conventional generation over the mid- to longer term. It is becoming clear that not only must operating procedures evolve to better accommodate variable resources, but also market transformation must ensure appropriate payments for needed energy, capacity, and ancillary services. RE Futures explores some of the operational implications of very high levels of renewable generation (up to 80% renewable generation by 2050).

In many cases, more cost-effective, higher-quality renewable resources are located far from major load centers. Expansion of the electrical transmission system is needed to access and

[62] See Cochran et al. (2012) for an international perspective.

deliver location-constrained renewable resources. Typically, transmission costs averaged across the United States constitute only approximately 10% of the final delivered cost of electricity and are responsible for a relatively small portion of the investment needed to bring energy from a remotely sited generator to load. However, siting and permitting of transmission, particularly lines spanning multiple jurisdictions, is a challenging and lengthy process.

Future transmission planning needs to be done proactively, looking many (20–40) years into the future, to pursue a broad range of long-term goals, including:

- Maintaining system reliability
- Ensuring adequate dynamic power transfer capability
- Ensuring just and reasonable rates
- Providing access to the most cost-effective renewable (and other) resources
- Electrifying transportation
- Supporting functional electricity markets by minimizing congestion
- Planning for future transmission corridor capacity needs, not just those immediately apparent
- Considering all options, including extra-high-voltage AC and DC, and technology advances such as superconductors and "undergrounding"
- Ensuring non-wire options are fully considered (e.g., efficiency and local distributed generation)
- Minimizing local, regional, and global environmental impacts, including reduced emissions of greenhouse gases, criteria pollutants, mercury, and other harmful pollutants.

All of these goals are driven by the need to optimize societal benefits of the power system relative to costs incurred.

In addition to transmission, greater operational flexibility will be needed to support high levels of renewable generation. Means to provide this include the following options, some of which are already emerging in practice:

- Enhanced balancing authority cooperation, coordination, or consolidation (as has occurred in Texas, PJM, and MISO)
- More efficient markets with shorter clearing periods, down to 5–10 minutes (as is the case already in MISO, PJM, and other regions)
- New ancillary service markets covering a wider range of needs (e.g., flexibility—faster ramp rates) beyond regulation and reserves markets already operating in much of the United States
- Unit commitment adjustments within the day
- New conventional generation technologies or modifications to existing generators that allow faster ramp rates, lower minimum output levels, quicker start times and shorter minimum-off times

- Improved wind and solar forecasting—along with efficient use of forecasts (as is now occurring in many regions)
- Increased connectivity among neighboring and distant regions
- Expanded electricity flow across the Eastern, Western, and ERCOT Interconnections
- Increased use of demand response (as is occurring now in PJM, ERCOT, California, and other regions)
- New, manageable electrical loads such as electric vehicle charging
- Increased use of storage options.

As described in Volume 1, RE Futures has found that at the hourly simulation level and for the cases examined, the system can meet projected loads with high levels of renewable electricity, including high levels of variable renewable generation. However, the investigation of system reliability—which requires detailed analysis down through the level of a few minutes to a few seconds and the investigation of system security (e.g., through stability and AC power flow analysis) for these high levels of renewable generation—remains to be done. As indicated in this volume, additional studies and experience are needed to examine in more detail, particularly at the sub-hourly level, the quantitative impacts of high renewable generation futures and then validate the measures suggested for addressing the electric power system operating challenges arising from these impacts.

Additional Research and Analysis Needed

RE Futures examined long-term planning issues, including transmission and generation issues stemming from operation of the electric power system with renewable energy penetrations of 80% and higher. The modeling was done with a standard industry production simulation model that runs on an hourly time step, observing transmission constraints, minimum up-times and downtimes, minimum turndown levels, and unit ramp rates. The model performs economic unit commitment and economic dispatch, based on an optimization that meets load and reserve obligation at minimum cost, subject to various constraints on the system. However, more work must be done to ensure the reliable operation of a system, including the following activities, listed by category:

- Data Development
    - Acquiring more detailed data on the output of variable and renewable resources over large footprints and the correlation of these resources with load. To provide good statistics, years of data are desired, as are new techniques for scaling limited data
- Model Development
    - Developing true stochastic planning and operations tools and models that can better address the increased stochastic nature of high penetration levels of variable generation
    - Developing detailed dynamic models of current and anticipated load to marry with improved and detailed models of supply technologies
    - Improving understanding and developing better models of the operation of conventional power generation technology operating with greater demands on

ramp rates and minimum turndown levels; also needed are approaches to retrofit high ramp rates and minimum turndown levels into existing plants as well as develop new fossil energy and nuclear energy units with improved flexibility
    - Developing improved models for forecasting day-ahead and hourly performance of weather-dependent variable renewable resources, as well as longer-range forecasts, and incorporation of these models into system operations
- Analysis
    - Conducting sub-hourly feasibility analyses under a wide variety of conditions, including the impact of potential changing weather patterns.
    - Studying interconnection-wide power system dynamics and system reliability and stability under high renewable generation scenarios, with variable and renewable resource models that have frequency and inertial response built into their representation of control systems; the same studies need to include HVDC lines with full converter control capability
    - Understanding the potential impacts of balancing authority consolidation (and/or seamless coordination) on system reliability, economics, and access to remote resources
    - Assessing required evolution of methodology to identify appropriateness and accuracy of required resource reliability standards
- Market, Business Model, and Regulatory Practice Evolution
    - Addressing technical and institutional issues to permit sub-hourly scheduling to access the flexibility of the markets so that regulation, the most expensive ancillary service, does not have to be relied on to balance within the hour
    - Conducting research on market changes that may be needed to deal with generation that has near-zero marginal costs
    - Exploring alternative business models and regulatory practices for transmission planning, siting, and permitting to enable necessary and economic development of transmission; a particularly important issue to explore is methods to improve collaboration for the planning, siting, permitting and cost allocation of transmission lines that cross multiple states.

RE Futures provides a foundation for future studies that explore further the various sensitivities and scenarios associated with renewable electricity that could impact the electricity sector's future. This analysis of bulk power issues in high renewable electricity futures identifies the significant opportunities that such futures open, the challenges that they pose, potential pathways to addressing these challenges, and future analytical needs to better understand and address them.

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