



Energy & Infrastructure Program

Energy Project

Capitalizing on the Evolving Power Sector:

Policies for a Modern and Reliable U.S. Electric Grid



February 2013



BIPARTISAN POLICY CENTER

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Summary of Findings and Recommendations

The U.S. electric power sector faces a significant transition over the next decade, with implications for the cost, reliability, and environmental impacts of the electricity supply. Specifically, economic trends and state and federal energy and environmental policies will continue to increase the share of natural gas and renewable energy in the generation mix. This ongoing shift provides an important opportunity to consider policies and institutional structures that help the electric grid adapt to changes in market conditions, policy, and technology in ways that enhance system reliability and maintain affordability. Low natural gas prices in the near- to medium-term will be a key driver of changes in the sector and further underscore this opportunity. As the fuel portion of the cost of electricity declines for many customers, there is a strong argument for an increased focus on the investment necessary to build a modernized grid that will deliver electricity that is both affordable and reliable.

This report provides findings and recommendations from the Bipartisan Policy Center's (BPC) Electric Grid Initiative, a year-long effort to develop policy recommendations that enhance the efficiency and reliability of the U.S. electric grid. BPC convened a diverse and bipartisan task force of stakeholders from energy companies, public utility commissions (PUCs), regional transmission organizations (RTOs), academia, and non-governmental organizations (NGOs). The task force developed recommendations in four broad policy areas: (1) encouraging efficient transmission and distribution investment, (2) advancing planning and operational coordination across jurisdictions, (3) enabling a more flexible and resilient system, and (4) monitoring and enhancing operational reliability. Major findings and recommendations are summarized below.

Encouraging Efficient Transmission and Distribution Investment

The U.S. electric power sector will need to make significant investments in transmission and distribution infrastructure over the next decade. In some regions, additional transmission

facilities, including lines crossing state boundaries and federal lands, will be needed to bring online new renewable generation driven by both increasingly stringent state renewable portfolio standards and federal incentives. New transmission investments will also be needed in some areas to maintain reliability. Constructing these facilities entails complex decisions about siting and cost allocation. With respect to distribution, upgrades to distribution systems that incorporate cost-effective smart grid technologies and add capacity will be essential to allow non-transmission alternatives, such as certain forms of energy storage, distributed generation, energy efficiency, and demand response, to reach their full potential.

Finding: State law governing siting and an emphasis on state-specific interests may impede or delay the construction of long-distance high-voltage interstate transmission lines with broad regional benefits. This siting challenge may be particularly pronounced for high-voltage direct current (HVDC) lines, which may not connect to the grid in intermediate states through which they pass.

Recommendations: Congress should enact a new, targeted backstop siting authority that allows the Federal Energy Regulatory Commission (FERC) to issue a federal permit approving multistate HVDC or 765+ kV AC transmission projects if:

- a state siting authority has denied the project without offering an alternative route that is consistent with relevant state law, or has not issued a decision within 18 months of receiving a completed application, or has insufficient authority to grant such an application; and
- the project has been approved by a state siting authority in another state.ⁱ

ⁱ Note that the National Association of Regulatory Utility Commissioners (NARUC), a contributing organization to BPC's Grid Study, strongly opposes this recommendation on the grounds that it calls for the expansion of the federal government's authority to site transmission facilities. See page 68 for NARUC's statement.

The backstop siting process should provide opportunities for state input on permit conditions. This new authority would be coupled with repeal of the current backstop siting authority. In addition, states should review their existing siting statutes and update them if needed, in a manner consistent with existing consumer protections, to ensure that state review processes are available to the full range of potential transmission project developers.

Finding: When transmission lines cross federal lands, or otherwise trigger the need for federal approval, inefficiencies in the federal review process can dramatically compound delays and increase overall project costs. While recent steps have been taken to improve coordination between federal agencies, additional reforms are needed.

Recommendations: The federal government should undertake a variety of measures to improve the federal siting process, including providing formal guidance affirming the use of appropriate federal lands (under specified conditions) for transmission projects, executing memoranda of understanding with state agency leaders to provide for coordinated and timely project reviews, and designating specific senior agency officials as responsible for ensuring the timely review of proposed projects. Congress should ensure that all federal agencies involved in transmission siting have sufficient cost recovery authority.

Finding: The current policies governing transmission development and cost recovery tend to result in transmission projects that accommodate only planned generation capacity, and thus are not adequately sized to preserve options for adding transmission capacity on scarce rights of way or to accommodate future renewable energy projects, which are often remotely located and integrated by long lines. The result can be an inefficient use of scarce rights of way, and an excessively costly, piecemeal build out of transmission.

Recommendations: FERC should clarify that regional transmission expansion plans may appropriately include

– and provide cost allocation for – projects with capacity that will not be utilized immediately if such projects: (1) enable the efficient use of scarce rights of way, or (2) serve location-constrained generation, and in either case will provide regional benefits (including transmission access for future renewable development) over the life of the project. FERC should also encourage specific methods of right sizing – such as the construction of double-circuit towers with only one circuit initially conductored – that reduce siting impacts.

Finding: Investments in the distribution system are essential to fully exploit the benefits of advanced grid technologies. Currently, some distribution utilities and state PUCs may be reluctant to invest in grid modernization because of the uncertain benefits of these investments. Further, as integration of advanced distribution-level technologies moves forward, the traditional relationship between transmission and distribution systems may change, raising new challenges for existing planning processes.

Recommendations: The U.S. Department of Energy (DOE) should fund an effort to identify best practice policies for state PUCs to encourage modifications of distribution infrastructure for the integration of advanced grid technologies. In addition, FERC should encourage coordination between utilities, state PUCs, and transmission planners in the consideration of distribution-level investments that have benefits to the regional transmission system as part of regional planning processes. Further, DOE, FERC, state PUCs, transmission planning authorities, and utilities should pursue new consultation and information-sharing mechanisms to consider regulatory, technical, and analytical issues pertaining to the interactions between transmission and distribution.

Enhancing Planning and Coordination across Jurisdictions

As the grid becomes increasingly integrated, policy and operational decisions made in one region will increasingly affect other regions. However, regions vary in market structure, policy priorities, and generation resource mix, creating challenges to effective coordination. Improved coordination across jurisdictions could enable the system to achieve the goals of enhancing reliability and integrating clean energy generation more efficiently.

Finding: Transmission planning and operational coordination across utilities and regions has important potential benefits, including the potential for more efficient infrastructure investment and a reduction in the impact of discrepancies in market rules that increase or shift costs and threaten reliability.

Recommendations: Congress or DOE should consider funding appropriate entities to continue existing interconnection-wide transmission analysis efforts. In addition, to enable effective interregional coordination under Order No. 1000, FERC should provide clarification and policy guidance regarding the specific requirements of the interregional coordination provisions of Order No. 1000, so that industry compliance filings will better serve the Commission's intent for interregional coordination. This guidance should encourage neighboring regions to address, in their agreements, seams issues that may interfere with efficient power market operation. In addition, FERC guidance should be appropriate to conditions found in each interconnection, with the intent of expanding the level of interregional coordination presently found in each interconnection.

Finding: Successful coordination between regional transmission planning processes under Order No. 1000 and utility integrated resource planning (IRP) and state energy planning processes could enable better use of information by all parties.

Recommendations: DOE should provide funding for an appropriate contractor(s) to work with states and utilities to develop best practices for coordinating utility integrated resource planning or state energy planning processes with regional transmission planning processes. Regional transmission planning entities should work with states in their regions to improve coordination on the analytics and timing of state and utility planning processes, so that regional transmission planning processes can benefit from information in state and utility processes, and vice versa.

Enabling a More Flexible and Resilient System

Improving grid flexibility can promote both operational reliability and the cost-effective integration of variable energy resources (VERs) such as wind and solar generation. While fast-ramping thermal generation units and advanced transmission technologies are clear sources of flexibility, flexibility can also be provided by resources such as demand response, energy storage, and dispatchable distributed generation. In addition, greater cooperation among utilities through measures such as dynamic scheduling, sharing of flexible reserves, and geographically broad real-time balancing markets can increase system flexibility. In some circumstances, deployment of these resources may reduce the need for new generation or transmission facilities, avoiding the capital cost outlays and siting controversies inherent in such projects. Further investment in grid modernization can greatly enhance the potential of these resources to provide system flexibility and reduce the need for future capacity investments.

Finding: Although many utilities have made some investment in advanced distribution system technologies, traditional cost-of-service regulation may fail to adequately value the benefits of these technologies. Incentive-based ratemaking may more effectively encourage efficient investments in advanced distribution system technologies.

Recommendation: The National Association of Regulatory Utility Commissioners (NARUC) should work with state PUCs to identify suitable, output-based distribution system performance metrics that could be used in incentive-based regulatory proceedings. In addition, DOE should fund NARUC or state efforts to develop model language for incentive-based regulation.

Finding: Improving the ability of customers or third-party service providers to utilize the output of advanced metering systems is an essential step in realizing the full potential benefits of a modern grid.

Recommendations: Utilities and state PUCs should offer dynamic retail pricing of electricity as an option where advanced metering infrastructure exists. States regulators should also ensure that customers are able to make their usage information available to third-party demand response aggregators or other service providers in a secure and privacy-protected format. Finally, where utilities have installed or plan to install advanced metering infrastructure, state PUCs should require that they conduct the necessary consumer education and outreach.

Finding: Demand response can improve system flexibility, efficiency, and reliability. In some circumstances, demand response may be a cost-effective alternative to new transmission or generation investment. Despite growth in demand response program offerings and participation, there remains significant untapped potential in this resource.

Recommendation: Market operators and regulators should permit demand response resources that are capable of performing in a manner comparable to conventional generation to participate in electricity markets and auctions on the same terms as generation resources.

Finding: While advances have been made in the development and deployment of advanced grid technologies, there are some key areas with substantial potential system-wide benefits that warrant continued or expanded federal involvement in research and development (R&D). Specifically, there is a role for DOE in R&D efforts to reduce the cost of energy storage technologies, develop analytic tools and software for transmission planning over larger geographic regions, and develop software for the aggregation and analysis of phasor measurement unit (PMU) data.

Recommendation: DOE's R&D portfolio should emphasize the relevance of these three technology areas to the development of a more efficient and reliable grid. For storage specifically, R&D efforts should target technology breakthroughs that have potential to significantly improve the economics of storage. More broadly, DOE should provide support for the deployment of advanced grid technologies and compile lessons learned from ongoing deployment efforts.

Monitoring and Enhancing Operational Reliability

A reliable electric grid is essential to the health of the U.S. economy. Given the costs associated with outages, enhancing reliability can provide broad economic benefits. In light of ongoing changes in the electricity generation mix, and particularly the increasing penetration of VERs, it is an important time to consider options for enhancing the reliability of the overall system. Efforts by the North American Electric Reliability Corporation (NERC) and FERC to improve data quality and the cost-effectiveness

of reliability standards will be important to achieving this goal. In addition, improvements in industry practices will be needed.

Finding: Evaluating trends in grid reliability, particularly at the distribution level, can be challenging due to incomplete and inconsistent data. While transmission-level reliability data has historically been limited, NERC has made important progress in collecting and publishing detailed reliability data. At the distribution level, insufficient and inconsistent data availability remains a significant challenge to assessing and improving reliability.

Recommendations: NERC should continue its efforts to develop consistent transmission reliability and outage data and events analysis. NARUC should encourage states to enact uniform standards – possibly based on the existing Institute of Electrical and Electronics Engineers (IEEE) standards – for distribution-level reporting.

Finding: Prompt dissemination of lessons learned from reliability events is essential to enabling improvements in the reliability of the electric system.

Recommendations: NERC should continue to improve its events analysis program and evaluate whether civil penalty liability impedes the timely sharing of information on outage causes.

Finding: Real-time sharing of operational reliability data among grid operators could allow significant reliability events to be anticipated and avoided.

Recommendations: NERC should require the real-time sharing of PMU and other operational data among transmission owners and operators, balancing authorities, reliability coordinators, and market operators, and work to identify mechanisms for protecting sensitive information. Appropriately time-lagged data should be shared with unaffiliated researchers.

Finding: Neither NERC nor FERC explicitly applies cost-benefit principles or evaluates economic impacts on consumers when formulating and approving reliability standards. Some reliability standards may yield uncertain reliability benefits while consuming utility resources and imposing significant costs on consumers.

Recommendation: NERC and FERC should support an increased role for cost-benefit analysis, building on NERC's Cost Effectiveness Action Plan. In particular, NERC should implement formal cost-benefit analysis as part of its standards development process, and when reviewing existing standards. Any analysis should appropriately consider that the reliability events that some of the standards are designed to prevent are low-probability but high-consequence in nature.

Finding: Balancing authorities are key institutions for ensuring electric reliability. However, the historical development of the transmission system and NERC's current process for approving the creation of new balancing authorities has led to the existence of balancing authorities in some regions that are insufficiently large or diverse to ensure reliability, operate efficiently, or integrate VERs efficiently. These conditions may lead to inefficient transmission system operation and expansion and have adverse impacts on system reliability and consumer costs.

Recommendations: NERC and FERC should review and modify the criteria for approving the creation of new balancing authorities, and should consider the consumer costs associated with VER integration for any new balancing authority proposal. Upon request by a state PUC, load-serving entity, balancing authority, or another entity with reliability management responsibilities, NERC should fund a study to assess the potential benefits of balancing area consolidation in the requesting region. In the West, where numerous small balancing authorities exist and VER integration is a challenge, FERC and the Western Electricity Coordinating Council (WECC) should consider

whether existing balancing authorities are appropriately configured to operate reliably and integrate VEs efficiently, and should recommend consolidation where appropriate. Finally, in considering proposals for ancillary services to be charged to VEs, FERC should consider whether a transmission provider has taken steps to minimize integration costs, such as cooperating with other balancing authorities through measures such as dynamic scheduling or an energy imbalance market.



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Chapter 1: Introduction

As economic trends and environmental policies continue to change the composition of electricity generation in the United States, the electric power industry confronts a number of important challenges that could raise the overall costs of this transition to cleaner energy and impede improvements to reliability or the affordable delivery of electricity. Failure to adequately address these challenges could undermine progress toward our nation's economic, security, and environmental goals. Key challenges include enabling necessary transmission system expansion and distribution system upgrades, while allowing competition from non-transmission alternatives; encouraging coordination in planning and operation across jurisdictions; integrating advanced grid technologies that improve system flexibility and resiliency; and finding cost-effective ways to enhance grid reliability.

These challenges to the U.S. electric grid exist against a backdrop of institutional complexity. Policies that impact investment in and operation of the U.S. grid are set by a mix of state and federal agencies, publicly owned utilities at the federal, state, and municipal level, and electric cooperatives. In addition, different regions of the country vary dramatically in their market structure for electricity services. Given the existing diversity in policy priorities, resource mix, and market structure, different regions can be expected to take very different approaches to addressing the challenges noted above. Nevertheless, all the institutions involved in operating the electric grid share the desire for reliable, affordable, and safe electricity. Similarly, there is a long history of bipartisan support for legislation to advance these goals that has resulted in important improvements to the reliability of the electric grid.

Within this context, the BPC Electric Grid Initiative has sought to develop policy recommendations that enable the transition in the electric power sector to occur in a manner that promotes cost-effective development of resources and enhances electric system reliability. To that end, BPC

convened a diverse task force that includes representatives from energy companies, PUCs, RTOs, academia, NGOs, and other experts. The task force met three times in 2012 and held numerous conference calls to discuss issues and consider potential recommendations that could have an impact in the near- to medium-term. In general, BPC's goal was to identify cost-effective policies that would foster a modern and efficient grid, could provide multiple benefits (e.g., improved system reliability and effective integration of intermittent renewable resources), and could be supported by the widest possible group of stakeholders.

The task force identified a menu of recommendations for Congress, federal agencies, states, and RTOs and independent system operators (ISOs). These recommendations are not intended to represent a comprehensive set of policies for the power sector. Rather, they highlight important areas where this diverse, bipartisan group of stakeholders agreed that progress could be achieved in ways that acknowledge and accommodate the diversity of the U.S. electric grid and the institutions that operate it. A "one-size-fits-all" approach would not be appropriate given the institutional and market diversity that exists across the U.S. Not all of the task force's recommendations are feasible or advisable in every region, state, or market structure.

Further, it is important to emphasize that this report is the product of a group whose members have diverse expertise and affiliations, and who came together to consider a number of complex and contentious topics. It is inevitable that arriving at a consensus document in these circumstances entailed numerous compromises. Accordingly, it should not be assumed that every member agrees with every formulation in the report, or that every member would support a given recommendation if it were taken in isolation. Rather, the task force has reached consensus on the report and its recommendations as a *package*, which, taken as a whole, offers a balanced

approach to many of the challenges facing the U.S. power sector over the next decade.ⁱⁱ

Report Structure

This report is organized as follows. Chapter 2 provides an overview of the U.S. grid and discusses key trends and issues that affect the reliability of the grid as it transitions to cleaner generation. Chapter 3 focuses on policy issues and recommendations that address the need for efficient investment in transmission and distribution infrastructure. Chapter 4 makes recommendations for improving coordination in transmission planning and operations across regions and between regional planning entities and states. Chapter 5 discusses recommendations targeted at enhancing system flexibility and resiliency through the integration of advanced grid technologies. Chapter 6 summarizes key challenges and recommendations pertaining to monitoring and enhancing operational reliability. Chapter 7 summarizes conclusions and identifies next steps.

ⁱⁱ Note that NARUC played an invaluable role as a resource to the task force. However, as an organization with its own process for adopting policies and resolutions, NARUC does not endorse the recommendations in the report. See page 68 for a full statement from NARUC.

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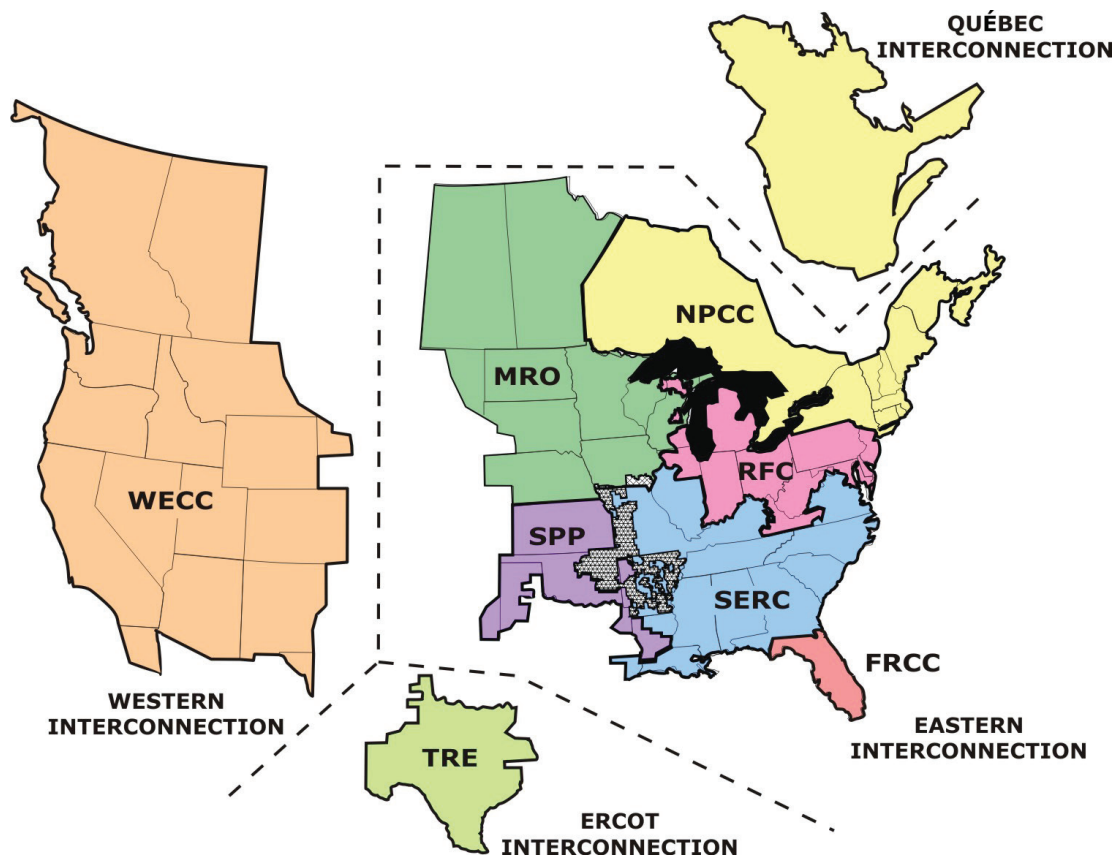
Chapter 2: The U.S. Grid and Emerging Power Sector Challenges

Overview of the U.S. Grid

The U.S. grid is comprised of three separate interconnections, as shown in Figure 1. The Western Interconnection serves the Western states, parts of Texas, and parts of Canada and Mexico. The Electric Reliability Council of Texas (ERCOT) serves most of the state of Texas. The Eastern Interconnection serves the eastern U.S. and parts of Canada. The three interconnections are tied to each other by a small number of low-capacity direct current (DC) transmission lines.¹

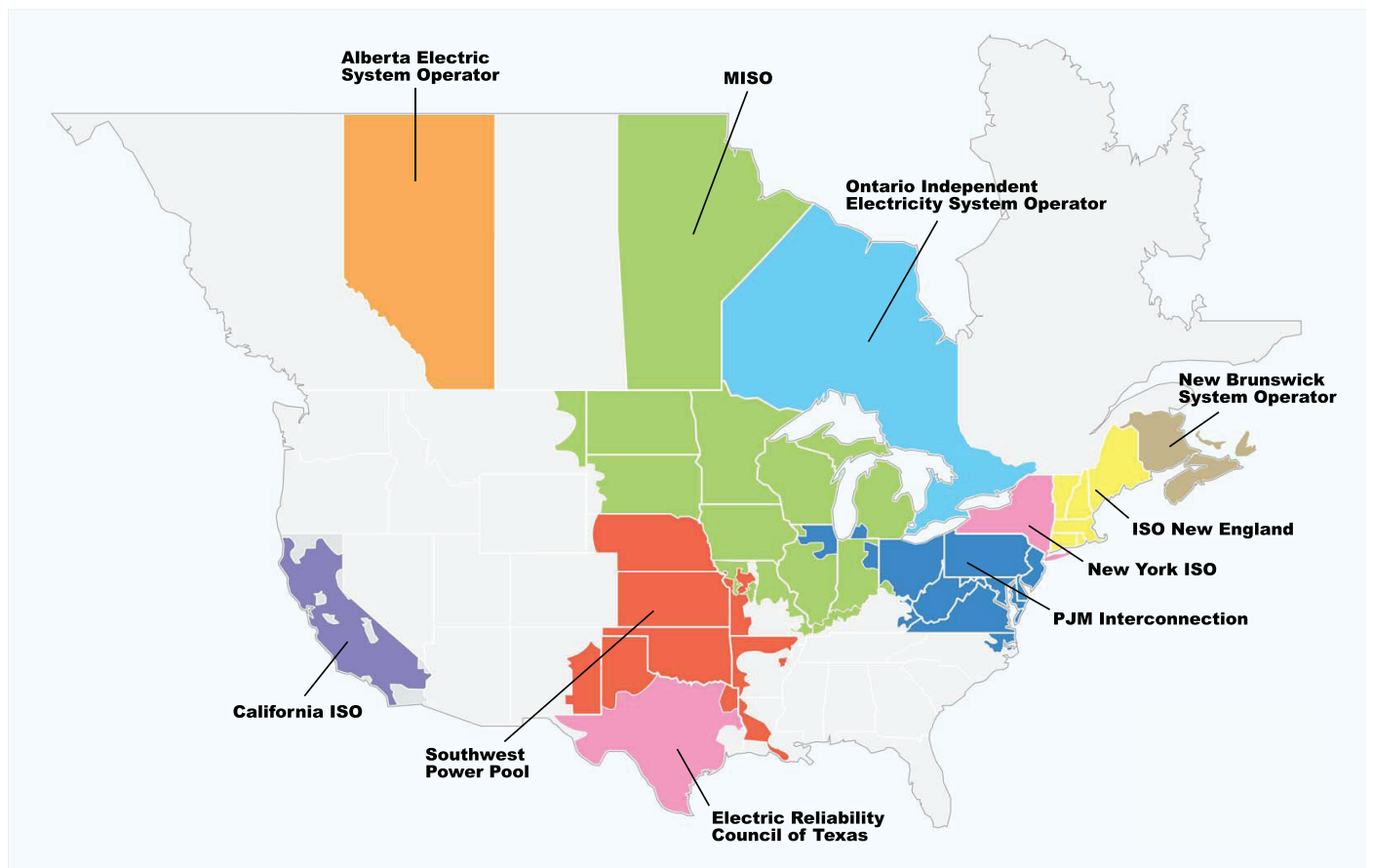
A variety of actors operate the bulk power system, which is comprised of generation and transmission facilities and their operating systems. Until the early 1990s, electric utilities were typically vertically integrated, which meant that an individual utility owned and operated the generation, transmission, and distribution resources in its footprint. The 1992 Energy Policy Act, followed by FERC Orders Nos. 888² and 889³ in 1996, provided the foundation for a transition toward competitive wholesale power markets by requiring investor-owned utilities to provide non-discriminatory access to their transmission

Figure 1. U.S. Interconnections and NERC Regions



Source: "Regional Entities." North America Electric Reliability Corporation. <http://www.nerc.com/page.php?cid=1191119>.

Figure 2. RTO and ISO Boundaries



Source: "ISO RTO Operating Regions." ISO/RTO Council. <http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/k.B14E/Map.htm>

lines and establishing standards for doing so. Order No. 888 also encouraged the voluntary formation of ISOs, to which utilities would transfer operating control of their transmission facilities as a mechanism for ensuring open access and organizing regional electricity markets. FERC Order No. 2000, issued in December 1999, took this concept a step further by finding that management of transmission by independent regional entities would "effectively remove" impediments to fully competitive markets.⁴ Order No. 2000 required utilities that own transmission facilities to place their

transmission under the control of an RTO, or inform FERC of the obstacles to doing so.⁵ Currently, RTO- and ISO-operated transmission grids serve approximately two-thirds of U.S. electricity demand.⁶ RTOs and ISOs also assess transmission needs and conduct transmission planning, and, in most cases, operate electricity markets. Existing RTOs and ISOs are shown in Figure 2. In regions where the transmission system is not managed by an RTO or ISO, electric utilities have generally remained vertically integrated, although most adhere to the separation of reliability and merchant

functions as specified in FERC Orders No. 888 and 889. In addition, federal enterprises, such as the Bonneville Power Administration (BPA) in the Northwest and the Tennessee Valley Authority (TVA) in the Southeast, play an important role in grid management, operating about 14 percent of the circuit miles of high-voltage transmission in the United States.⁷

Balancing authorities play an essential role in the operation of the bulk power system; they are responsible for balancing electricity supply and demand in real time over a defined control area, in accordance with reliability standards set by NERC and FERC. There are currently 133 balancing authorities regulated by NERC (Figure 3).⁸ In many cases, particularly along the east coast, individual RTOs serve as a single balancing authority. The Southwest Power Pool (SPP), on the other hand, currently has 17 balancing authorities, and WECC has 38 balancing authorities.⁹ In regions without RTOs, where transmission remains owned and operated by vertically integrated investor-owned utilities, publicly owned utilities (federal, state, or municipal), or rural cooperatives, the consolidation of balancing areas has been significantly less pronounced. Although some vertically integrated companies in non-RTO regions operate as single balancing authorities geographically comparable in size to RTOs, in other cases, balancing authorities are comprised of a single utility or facility. NERC has noted that larger, more diversified balancing areas (or coordination agreements between balancing areas) offer reliability benefits while also enabling VER integration and increasing system flexibility.¹⁰ At the same time, pushes to consolidate existing balancing authorities have raised concerns about cost shifts.

The distribution of electricity to retail load is provided by about 3,200 load-serving entities (LSEs).¹¹ The majority (almost 2,200) of these entities are owned by federal, state, or municipal governments.¹² There are 815 electric cooperatives, accounting for approximately 11 percent of retail electricity sales.¹³ The majority of load (about 63 percent) is served by just fewer than 240 investor-owned

utilities.¹⁴ These entities provide distribution service to customers at rates approved by state PUCs. LSEs play an important role in maintaining the operational reliability of the grid as well as integrating new technologies and services, such as advanced metering and certain demand response programs.

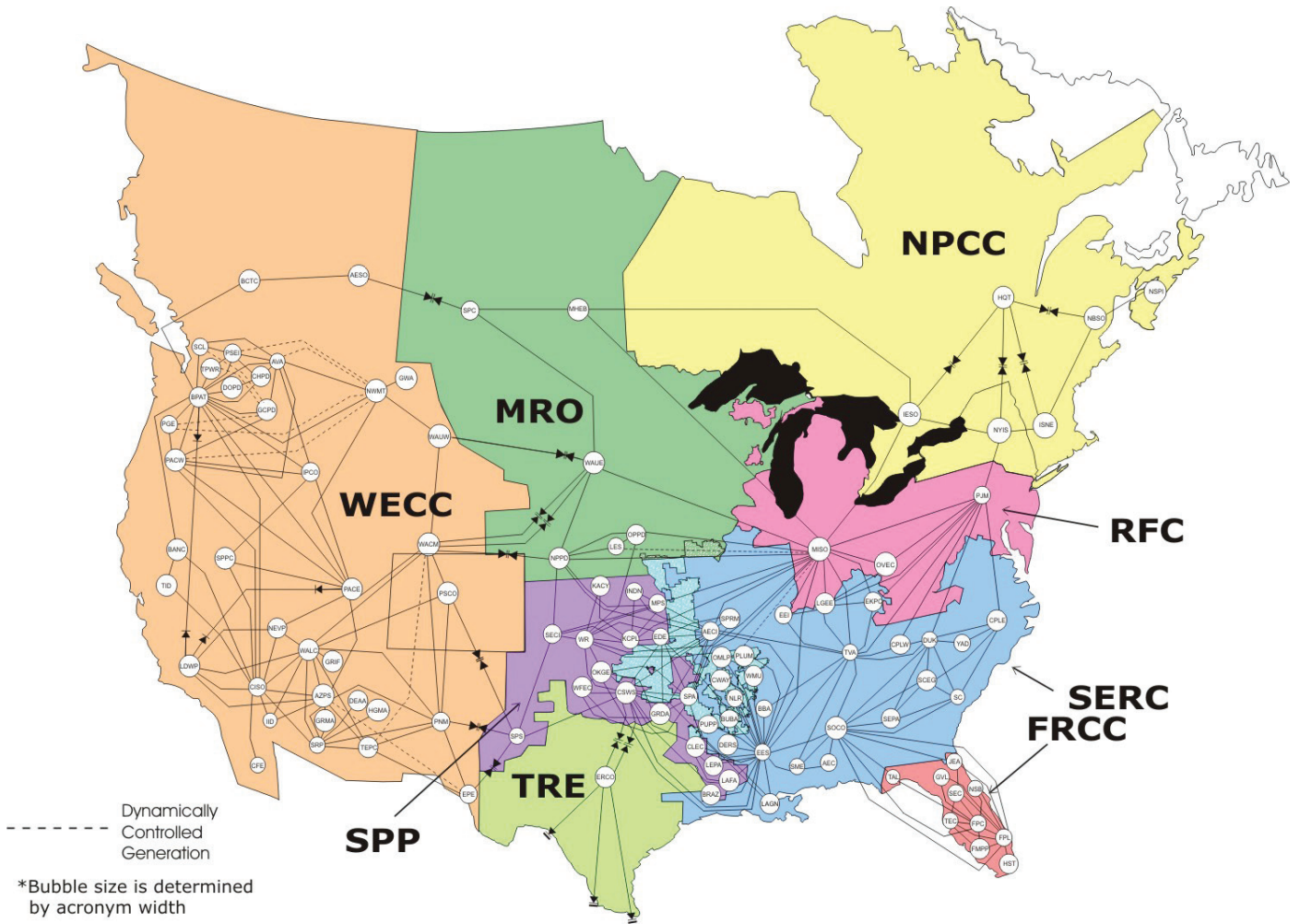
Important Challenges Facing the U.S. Power Sector

As noted in Chapter 1, as a result of both economic trends and state and federal energy and environmental policies, the power sector is in a period of transition, with renewable energy resources and natural gas comprising an increasing share of the generation mix. This transition will have important implications for the cost, reliability, and environmental impacts of the U.S. electricity supply. Optimizing these three variables for customers will require the efficient build-out of necessary transmission infrastructure, as well as the cost-effective integration of advanced grid technologies and alternatives to transmission such as demand-side resources. Coordination between the many institutions that govern or operate the U.S. grid will be necessary to ensure that power sector investments made over the next 10 years provide for affordable, reliable, and clean electricity in the decades ahead. In addition, efforts to improve analysis of grid reliability and promote data sharing among operators will provide important economic benefits both during this transition and beyond.

Integrating Variable Energy Resources

FERC defines “variable energy resources” as renewable energy resources that cannot be stored and have variability that is beyond the control of the facility operator.¹⁵ Policies such as state renewable portfolio standards and state and federal tax incentives have been the primary drivers of a substantial increase in the contribution of VERs, such as solar and wind energy, to the grid.¹⁶ Currently, 29 states and

Figure 3. North American Balancing Authorities as of July 2012



Source: "Regional Entities." North American Electric Reliability Corporation. 2012. <http://www.nerc.com/page.php?cid=1191119>.

Note: The highlighted area between SPP and SERC denotes overlapping regional area boundaries; for example some load serving entities participate in one region and their associated transmission owner/operators in another

the District of Columbia have renewable or alternative energy portfolio standards¹⁷ and most states as well as the federal government provide tax incentives for renewable energy development. Installed wind generation capacity stood at about 46 gigawatts (GW) in 2011, a nineteen-fold increase in capacity from 2000.¹⁸ Over the decade from 2000 to

2010, the electricity produced from all non-hydro renewables doubled as a share of the generation mix. NERC's 2012 Long Term Reliability Assessment projects that an additional 36 GW of nameplate wind capacity will be installed from 2012 to 2022.¹⁹ Given the expected growth in renewable energy investment, the set of policies and market conditions that

affect VER integration will have significant implications for grid operators' ability to add these resources in a way that maintains both affordability and reliability.

As FERC has noted, while VERs offer important benefits such as low variable costs and low pollutant emissions, they present important operational challenges – a lack of storage, the inability to time output to load, and the imprecision of wind and solar forecasts – that complicate their integration into the grid. FERC has taken a number of actions in recent years to address challenges specific to VER integration, including recent market reforms.²⁰

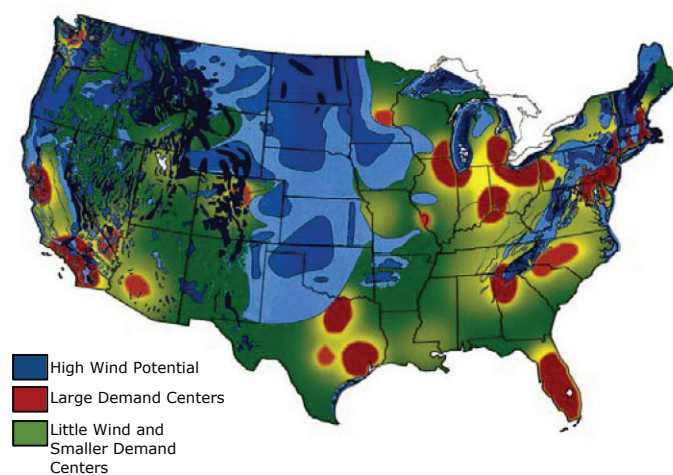
Another important challenge to VER integration is that the most significant and highest quality sources of renewable energy are often located away from load centers. Figure 4 demonstrates the distance between the location of wind resources and load centers in the U.S. Planning and constructing the long-distance transmission capacity necessary to support the development of many of these resources will require increased cooperation among utilities, RTOs, states, and the federal government. Cost allocation for new transmission facilities is another significant challenge.

Although challenges to VER integration exist nationwide, the specific nature of these challenges varies by region and market structure. Different regions have varied generation mixes, transmission infrastructures, and VER endowments. For example, the Pacific Northwest's challenges relate to the deployment of wind resources in a relatively concentrated geographical area, in combination with operational constraints on the hydropower resources that dominate the region's generation mix.²¹ The Southwest is focused on how to deploy solar resources.²² Smaller balancing authorities in these regions and others can increase the cost and challenge of reliably integrating VER generation.

In regions with RTOs or ISOs, the inherent resource diversity within these larger regions typically reduces the overall variability of total VER output. Different RTOs/ISOs are in

varied stages of incorporating VERs into their markets using different approaches.²³ This raises considerable concern in areas like the Midwest, where significant VER penetration is occurring on the seams without sufficient coordination between neighboring RTOs. Some areas of the country outside of RTOs/ISOs, such as the West, have numerous small balancing authorities, which creates greater difficulty in reliably and economically integrating VER generation.

Figure 4. Wind Resources and Demand Centers



Source: "Accommodating High Levels of Variable Generation." North American Electric Reliability Corporation. 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf.

Managing the Grid Impacts of the Changing Economics of Coal and Natural Gas

Electricity from coal continues to represent a large share of the nation's generation mix.²⁴ However, a number of economic and regulatory factors are expected to lead to the retirement of many of the nation's oldest and least efficient coal plants. According to recent counts by Credit Suisse and the Edison Electric Institute (EII), companies have announced coal plant capacity retirements totaling 38 GW²⁵ to 53 GW²⁶ between 2010 and 2022, and more retirement announcements are likely. A recent BPC analysis projects that 56 GW of coal-fired capacity will retire by 2030.²⁷

A key driver of this shift is that expanding natural gas production from shale gas reserves has lowered natural gas prices, diminishing the cost advantage that coal plants once enjoyed relative to natural gas-fired plants. Natural gas spot prices have remained at or below \$3 per mmBtu through September of 2012.²⁸ Further, as shown in Figure 5, the U.S. Energy Information Administration (EIA) projects that natural gas prices will remain below \$5 per mmBtu through 2025.²⁹ At the same time, coal prices have been increasing due to growth in foreign demand, which has led to increased coal exports and higher mining costs. EIA is projecting that minemouth coal prices will increase by 35 percent from 2010 to 2020.³⁰

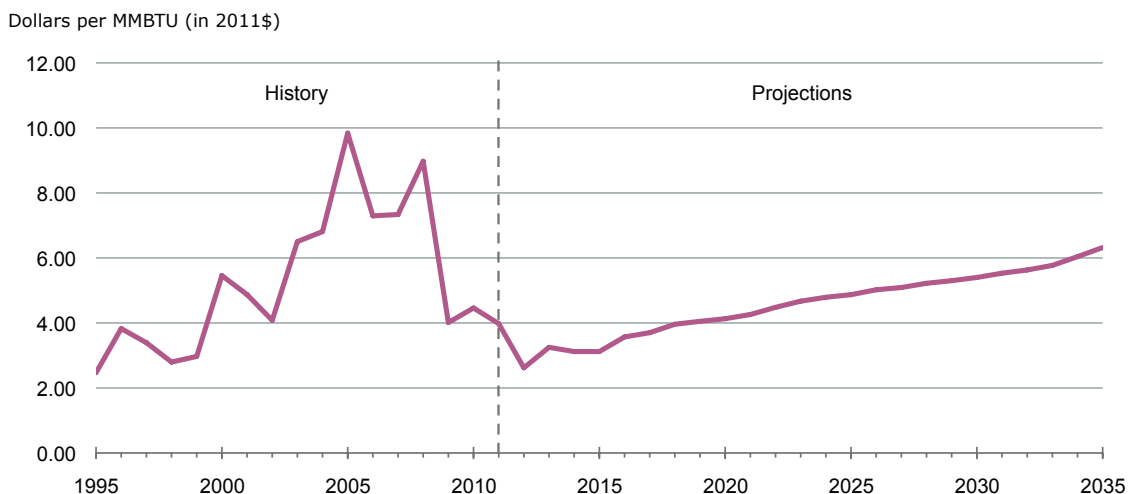
Second, recent EPA regulations affecting the power sector are expected to increase or accelerate retirement of some additional coal-fired capacity.³¹ Of the recent EPA regulations that affect power plants, the Mercury and Air Toxics Standards (MATS)³² rule is likely to have the most sizeable effect. The Cross-State Air Pollution Rule (CSAPR), also finalized in 2011,³³ was designed to reduce power sector

sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emissions in the Eastern U.S., but it was vacated by the D.C. Circuit Court in August 2012.³⁴ CSAPR's predecessor, the Clean Air Interstate Rule (CAIR) remains in place in the interim as EPA works on a new rule.³⁵

Finally, a decline in electricity demand due to the recession and relatively low demand growth projections going forward have resulted in additional economic pressure on less efficient coal plants in some regions. EIA projects that U.S. electricity demand will grow at a rate of about 0.8 percent per year for the next 15 years.³⁶ This projected growth rate is substantially down from the 1.2 percent per year growth rate projected in 2010 and the 1.4 percent per year growth rate projected in 2007.³⁷

These trends are particularly significant given the role that coal-fired power has historically played in providing baseload power and grid stability. Most thermal generation facilities currently being planned are natural gas-fired, and these plants, along with increased utilization of existing natural

Figure 5. Annual Average Henry Hub Spot Natural Gas Prices, 1995-2035



Source: "Natural Gas Supply, Disposition, and Prices." Annual Energy Outlook 2013: Early Release. U.S. Dept. of Energy, Energy Information Administration. <http://www.eia.gov/forecasts/aeo/er/index.cfm>.

gas-fired plants, are expected to replace a large share of the generation from retiring coal-fired capacity in some regions.³⁸

The ongoing shift from coal to natural gas raises both near- and longer-term economic and technical concerns. Near-term issues include the potential for short-term localized reliability concerns, the availability of adequate natural gas pipeline capacity to reach gas-fired generation, and the ability to coordinate delivery of natural gas with the timing of generation needs.³⁹ Longer-term issues include the economic and reliability implications of increased reliance on natural gas for baseload generation, given remaining uncertainty regarding shale gas resource development, and the potential price implications of increased demand for natural gas in other markets, including for residential use, manufacturing, transportation, and exports. Finally, while emissions of key pollutants are lower for natural gas combustion than for coal combustion, natural gas combustion does produce CO₂ and NO_x emissions, and shale gas extraction produces fugitive emissions of methane, a potent greenhouse gas.

At the same time, expectations of low natural gas prices going forward may be positive for the integration of VERs. Fast-ramping natural gas turbines frequently serve as providers of reserve power to accommodate the variability in VERs. For at least one utility, low natural gas prices have translated into lower costs for VER integration because of the resulting decline in reserve power generation costs.⁴⁰

Ensuring Development of Necessary Transmission Infrastructure

The increasing role of VERs and natural gas-fired generators creates a variety of transmission investment needs, ranging from relatively near-term needs for localized lines to maintain reliability and connect new capacity in the wake of coal-plant retirements, to an ongoing need for long-distance, high-voltage connections to utilize remote VERs. Transmission investment is critical for a number of reasons. Beyond enabling new generation resources to come online and

The Energy Policy Act of 2005 and the Electric Grid

The Energy Policy Act of 2005, passed with bipartisan support in the summer of 2005, was the first major energy legislation signed into law since 1992.

Prompted by concerns over escalating energy prices, dependence on foreign oil, and environmental issues, the legislation attempted to balance three main interests – economic growth, energy security, and environmental quality – amidst the changing U.S. energy landscape. The wide-ranging law contained a number of important provisions on electric grid issues, including:

Mandatory Reliability Standards – The statute amended the Federal Power Act to provide for a system of mandatory reliability standards to be developed and enforced by an Electric Reliability Organization (ERO) subject to FERC oversight. FERC designated NERC as the ERO in 2006. Mandatory reliability standards apply to all users, owners, and operators of the bulk power system.

Backstop Transmission Siting Authority – The law requires DOE to designate “national interest electric transmission corridors” in areas with capacity constraints or congestion. Within these corridors, FERC may authorize proposed transmission projects if a state cannot or does not authorize a project within one year or authorizes a project subject to unreasonable conditions. FERC’s authorization for a project grants the permit holder the ability to exercise eminent domain to acquire needed right of way.

Coordination of Federal Authorizations for Transmission – For transmission projects proposed to be built on federal lands or otherwise requiring federal regulatory approvals, the Act charges the DOE with serving as the lead agency to coordinate environmental reviews among the federal agencies involved.

Transmission Incentives – The Act requires FERC to establish incentive-based transmission rate policies to attract capital investment and allow recovery for costs of compliance with reliability requirements.

Figure 6. Actual and Planned Transmission Investment by Shareholder-Owned Utilities, 2006-2015

Source: “Actual and Planned Transmission Investment by Shareholder-Owned Utilities (2006-2015).” Edison Electric Institute 2012. http://www.eei.org/ourissues/electricitytransmission/documents/bar_transmission_investment.pdf.

supporting reliability, adequate transmission infrastructure is needed to hold down generation costs and allow the lowest-cost generators to serve load to the extent possible.

In the years following the electricity market restructuring efforts of the 1990s, there was considerable concern about a slowdown in the pace of transmission investment. In response, Congress enacted reforms as part of the Energy Policy Act of 2005 (EPAAct 2005) that directed FERC to establish incentive rates for transmission investment and provided backstop federal siting authority for some needed transmission projects.⁴¹

In recent years, the pace of transmission investment has increased, as shown in Figure 6. From 2005 to 2010, transmission investment in the U.S. grew at a rate of six percent per year; from 2010 to 2012, the average yearly growth rate was 17 percent.^{42,43}

NERC’s 2012 Long Term Reliability Assessment projected 29,600 circuit miles of new high voltage transmission from

2012 to 2022.⁴⁴ NERC previously noted that just over one-quarter of the planned high voltage transmission capacity would be needed for VER integration.⁴⁵

While NERC has found that projected transmission investments are likely to be adequate to reliably provide for forecasted electricity demand, NERC has also noted that delays related to siting and permitting can inhibit needed investment, and that the impact of these delays may be amplified as the economy recovers and pressures on the system from VER integration, resource retirements, and electricity demand growth increase.⁴⁶ In addition, it may be economically and environmentally efficient to build excess capacity into certain transmission projects given the scarcity of rights of way and the challenges of developing location-constrained renewable energy resources without existing transmission. The development of these resources can be impeded because it generally takes significantly more lead time to site, permit, and construct a high-voltage transmission line than it takes to site, permit, and construct new solar or

wind generation. In some regions, however, existing policies governing transmission cost allocation and rate recovery may not support investment in transmission capacity that could remain unutilized for a significant period of time, and in the case of merchant projects, it may be difficult to finance significant unsubscribed capacity.

Expected changes in the nation's generation mix over the next decade raise important challenges for policies pertaining to transmission planning and development. As the authors of a recent MIT study titled, "The Future of the Electric Grid," have noted, if renewable energy resources are to be developed in an efficient manner, "an increasing fraction of transmission lines will cross state borders, independent system operator (ISO) regions, and land managed by federal agencies such as the U.S. Forest Service."⁴⁷

Given the increasing need for long-distance transmission lines, a number of policy efforts have been initiated to promote transmission planning and coordination at a broader geographic scale. FERC Order No. 1000 requires transmission providers to participate in a regional transmission planning process and engage in interregional coordination with neighboring planning regions.⁴⁸ In addition, voluntary initiatives, supported by funding from DOE,⁴⁹ have been launched to attempt transmission expansion planning on a broader, interconnection-wide basis. These initiatives are taking place under the auspices of WECC, the Eastern Interconnection Planning Collaborative (EIPC), and ERCOT. If implemented effectively, regional, interregional, and interconnection-wide transmission planning has the potential to facilitate the development of grid infrastructure with broad-based system benefits, delivering cost and reliability benefits to consumers.

State and local governments retain primary authority over the siting of new transmission projects. Although EAct 2005 gave FERC limited backstop siting authority within designated National Interest Electric Transmission Corridors (NIETCs), this authority was significantly circumscribed by recent federal appeals court decisions.⁵⁰ Federal regulatory

approvals are required where transmission projects cross federal lands or impact endangered species, wetlands, or coastal areas. As a practical matter, obtaining federal approvals is sometimes the binding regulatory constraint on transmission development projects, especially in the West. EAct 2005 directs DOE to coordinate federal agency approvals, and the current administration has taken action to try to better coordinate and accelerate federal approvals for energy infrastructure projects.⁵¹

Enabling Advanced Transmission and Distribution Technologies and Non-Transmission Alternatives

Advanced or "smart" grid technologies provide new opportunities for enhancing system flexibility, responsiveness, and reliability. These technologies have the potential to enable a number of grid improvements that would lead to a cleaner, more efficient, and more reliable system, including increased integration of distributed generation, broader penetration of demand response programs, coordination of VER output with demand-side resources, enhanced efficiency and resiliency of transmission and distribution systems,⁵² and – as the economics of energy storage improve – increased deployment and management of energy storage resources. In some cases, these resources can serve as cost-effective alternatives to new transmission investment, with the additional benefit that they can postpone the costs and siting controversies associated with conventional transmission projects.

Despite a recent surge in grid modernization investments prompted by a combination of state and utility initiatives as well as federal funding, some advanced technologies – particularly advanced metering infrastructure – continue to face barriers including high initial costs, uncertain benefits, technological hurdles, and some public opposition. In the presence of uncertain benefits, some utility regulators have demonstrated reluctance to support utility grid modernization investments absent significant federal support. Further, some utilities themselves have been wary to undertake investments in advanced metering

given customer concerns over privacy and, despite evidence to the contrary, public health impacts.⁵³

An increasingly modern, digitized grid also gives rise to important security considerations. Concerns range from the

possibility that private consumer data could be compromised to the potential for cyber terrorists to shut down large sections of the grid. These risks raise complex and contentious questions regarding the appropriate roles of the private sector and the federal government in improving the cyber security

FERC Order No. 1000

Issued in July 2011, FERC Order No. 1000 altered requirements for transmission planning and cost allocation. The rule builds on the reforms of Order No. 890, issued in 2007, which required individual transmission owners to conduct transmission planning through a transparent process. Key elements of Order No. 1000 include:

Transmission Planning

- Each transmission provider is required to participate in a regional planning process to create a regional transmission plan. The regional planning process must comply with the planning principles already applicable to individual utility transmission plans under Order No. 890. This regional planning process must consider transmission and non-transmission solutions to meet the needs of the planning region. Transmission customers and other stakeholders must be given an opportunity to participate in the process.
- Each transmission provider must weigh transmission needs driven by public policy requirements established by state or federal laws, and evaluate proposed solutions to meet those needs. “Public policy” requirements may include, for instance, state renewable portfolio standards and similar policies to incentivize renewables.

- So-called rights of first refusal – which grant incumbent transmission owners rights that preclude competition for transmission development projects – contained in FERC-approved tariffs and contracts must be removed or limited.
- Transmission providers in adjacent transmission planning regions within the same interconnection must coordinate their transmission planning processes so as to collaborate to identify mutual transmission needs, evaluate potential projects, exchange data, and maintain communication forums.

Cost Allocation

- Each region must develop methods for allocating the costs of new transmission facilities that are included in the regional transmission expansion plan. Cost allocation methods must comply with six cost allocation principles found in Order No. 1000 to ensure, among other things, that the allocation of costs for new facilities is “roughly commensurate” with their benefits. A region may not rely on participant funding as its regional cost allocation methodology.
- Transmission providers in neighboring planning regions must develop a common interregional cost allocation method for new interregional transmission facilities. This methodology must satisfy six principles established by the rule. The interregional cost allocation methodology may be different than the regional cost allocation methodology.

of the electric grid and of other critical infrastructure. For example, one much-debated question is whether the federal government should be granted broad new authorities to regulate the cyber security of critical infrastructure and, if so, how such authority might be allocated across relevant agencies. Alternately, should the government instead focus on improving the sharing of information regarding vulnerabilities and security breaches? Within the electric sector, another important question is whether existing mandatory cyber security standards should be extended beyond the bulk electric system to distribution networks. Although a full discussion of cyber security issues is beyond the scope of this report, BPC plans to address these issues in future work.

Enhancing Reliability

Ongoing changes in the electric sector, as well as recent outage events,⁵⁴ have brought the issue of electric reliability to the forefront. Reliable electricity service is essential to the performance of the U.S. economy. Disturbances in the form of power interruptions, outages, and quality-related events impose significant costs on customers. A 2006 study conducted by the Lawrence Berkeley National Laboratory estimated the annual cost of power disturbances, excluding power quality incidents, at \$79 billion. Most of this cost – about \$57 billion and \$20 billion, respectively – is borne by the commercial and industrial sectors.⁵⁵ In practice, most outages (and therefore the largest share of costs) occur on distribution systems rather than on the bulk power system, particularly during the course of weather-related events. For example, FERC and NERC staff found that transmission outages accounted for less than five percent of customer outages associated with the nor'easter of October 29-30, 2011.^{56,57}

While states retain jurisdiction over distribution systems, NERC is responsible for the reliability of the bulk power system. NERC considers reliability along two dimensions: resource adequacy and security. Resource adequacy

refers to the ability of the electric system to meet the electricity requirements of end-use customers at all times, taking into account scheduled and reasonably anticipated unscheduled generator outages. Security refers to the ability of the bulk power system to withstand sudden, unexpected disturbances. Traditionally, such disturbances have included short circuits or the temporary loss of system elements due to natural causes, such as extreme weather events. More recently, NERC has expanded this concept to encompass intentional physical or cyber attacks on the grid.⁵⁸

EPAct 2005 authorized FERC to designate a national “electric reliability organization” that would have the authority to develop and enforce electric reliability standards, subject to FERC supervision. Pursuant to this authority, FERC designated NERC – a non-governmental organization with an independent board – as the national electric reliability organization in 2006. NERC is expressly barred from imposing resource adequacy requirements or requiring the construction of new or expanded generation or transmission capacity. However, it does assess resource adequacy each year with a 10-year forecast.⁵⁹

NERC develops and enforces reliability standards that address many of the issues that fall under the category of security. For example, reliability standards address such issues as infrastructure protection, resource and demand balancing, and transmission operation. Once approved by FERC, reliability standards act as binding requirements on entities engaged in the bulk power system, including RTOs/ISOs as well as owners, operators, and users of transmission and generation facilities.⁶⁰ NERC develops reliability standards through an industry consensus process. The current process for developing reliability standards does not explicitly weigh the implementation costs and reliability benefits of these standards, though NERC has begun initiatives to integrate cost-effectiveness considerations.⁶¹ In addition, NERC has not conducted ex post analyses of the costs and benefits of existing standards.

An ongoing challenge in terms of assessing the reliability of the grid is the need for consistent and complete publicly available data on system outages and their causes. With respect to transmission, outage data collected by DOE and NERC have historically had limited value for analysis of reliability trends.⁶² However, NERC has recently made important progress in its expansion of reporting requirements and data availability. With respect to distribution, where collection of data falls to individual states, variation in state requirements remains a significant obstacle. A lack of consistent information about system outages makes it effectively impossible to compare reliability across utilities, states, or regions, or to determine whether overall grid reliability has improved in recent decades.⁶³ In addition, there is need to improve real-time data sharing among grid operators so that potential reliability risks can be more easily mitigated.

Energy & Infrastructure Program
Energy Project



Chapter 3: Encouraging Efficient Transmission and Distribution Investment

As noted in Chapter 2, a number of trends in the power sector will create the need for significant infrastructure investment over the next decade. Long distance transmission, including lines spanning state boundaries or federally managed lands, will be needed to bring online the renewable generation required to meet the renewable portfolio standard targets of many states. In addition, aging infrastructure and pressures on reliability will require transmission investment. Transmission needs will vary by state and region, of course, depending on state policy goals, existing pressures on reliability and infrastructure, expected load growth, and generation retirements and additions. The construction of new transmission capacity – and particularly transmission that crosses jurisdictional lines – can bring with it complex and contentious policy debates with meaningful economic and environmental consequences. Siting approval and the allocation of transmission costs are particularly challenging issues.

In some cases, alternatives to new transmission such as more efficient use of existing wires or expanded deployment of demand response, storage, efficiency, or distributed generation resources may offer a more cost-effective solution for meeting system needs. FERC Order No. 1000 requires that such non-transmission alternatives be given equal consideration to new transmission projects in regional transmission plans.⁶⁴ Alternatives to new transmission may be particularly relevant as a way to alleviate load-balancing challenges associated with VER integration that might otherwise require expanded transmission capacity to import generation from other areas. Policy recommendations to enable alternatives to new transmission are discussed in Chapter 5.

Although much policy discussion has focused on the need for transmission system investments, it is worth emphasizing that distribution system infrastructure also plays a critical role in reliability. Hence, distribution system upgrades are an important component of grid modernization. Upgrading

distribution systems that were designed for radial load service will be necessary to optimally integrate non-transmission alternatives such as demand response, distributed generation, and certain forms of energy storage.⁶⁵

This chapter summarizes some of the key policy issues surrounding transmission and distribution system needs over the next decade, and offers policy recommendations intended to encourage efficient improvements to grid infrastructure.

Siting Approvals for Transmission Projects

Siting new transmission lines is often a prolonged, expensive, and contentious undertaking. The 1935 Federal Power Act left states with primary authority over transmission facility siting. At the time, transmission projects were typically built within the boundaries of a single state by a vertically integrated utility. In recent decades, however, the evolution of interstate and regional electricity markets has increasingly necessitated long-line, interstate transmission projects. Further, the extent of VER integration that will be required by existing state renewable portfolio requirements, and the reality that many renewable resources are located at a distance from load, will likely create a greater need for new long-line transmission in some regions.

The development of new transmission infrastructure raises important environmental concerns as well as concerns about impacts on property owners in the vicinity of the right of way. Under the current siting regime, the developer of a multistate transmission line must obtain requisite approvals from state and local authorities along the full length of the line, while also obtaining required federal and state environmental approvals. For their part, individual state authorities may be bound by state statutes to accept or reject the project on the basis of their in-state transmission needs, or the in-state benefits that the project offers. In these cases, states may not be empowered to consider the regional benefits of a proposed

project. Thus, a project that transmits power generated in one state, passes through a second state, and serves load in a third state could have difficulty winning approval from regulators in the second state. In some states, regulators might even be required by law to reject a project that does not serve load within the state's boundaries, even in cases where the project delivers broader benefits to the region at large that the state would share in over time.

Siting processes are particularly problematic for interstate projects that involve long-distance high-voltage lines, and especially extra high-voltage AC and high-voltage direct current (HVDC) lines. These lines are well suited for transmitting large amounts of power over long distances with better reliability, controllability, and efficiency than lower voltage lines.⁶⁶ HVDC lines, which typically transmit electricity from point-to-point, may not provide utility services in, or direct benefits to, each of the states through which they pass.⁶⁷ In such circumstances, obtaining necessary siting approvals through state regulatory regimes may be particularly difficult.

For example, in 2011 the Arkansas Public Service Commission effectively rejected a proposed HVDC line that was intended to transmit wind power generated in Oklahoma to customers served by the Tennessee Valley Authority (TVA). The Public Service Commission held that its statutory authority did not allow it to grant "public utility" status – a prerequisite for eminent domain authority – to a project that would not serve Arkansas customers. The commission expressed its support for the line as a matter of policy, but observed that "the law governing public utilities was not drafted to comprehend changes in the utility industry such as this one – where a non-utility, private enterprise endeavors to fill a void in the transmission of renewable power that is much needed."⁶⁸

In some instances, of course, a given transmission line may impose negative net impacts on some parties. Developers should therefore strive to maintain transparent consultation processes with affected communities, and work

collaboratively with these communities to identify potential ancillary benefits or other projects that would serve to offset negative impacts from a given line.

Despite the contentious nature of interstate transmission siting, it is important to note that a number of regions have developed collaborative interstate initiatives to foster more efficient planning and review. For example, the governors of Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin started the Upper Midwest Transmission Development Initiative in 2008 to better coordinate transmission planning, siting, and cost allocation within the region, with the goal of enabling the transmission investments needed to support renewable energy resource development.⁶⁹ Likewise, the New England States Committee on Electricity, which provides input to ISO New England's transmission planning process, has formed the Interstate Transmission Siting Collaborative to identify opportunities for better interstate coordination. While this type of collaboration should improve process efficiency, it generally does not negate the ability of an individual state to block projects that, despite their broader regional benefits, deliver limited or no in-state benefits.

When a proposed transmission project crosses federal lands managed by federal agencies such as the Bureau of Land Management (BLM) or the U.S. Forest Service (USFS), or when it requires federal permits under regulatory statutes such as the Clean Water Act or the Endangered Species Act, additional permitting challenges arise. Transmission projects in the western United States, where federal land holdings are vast, are particularly likely to require federal approvals. The federal siting process has historically been prone to significant delays. In a recent example, the developer of a 430-mile, 500-kV transmission line between Montana and Idaho asked the federal agencies involved to cease analyzing the proposed line. The developer noted that \$14 million had been spent to conduct analyses for the federal government over a period of four years, and yet the timeline for approval still remained uncertain.⁷⁰

Delays in the federal siting and permitting process can occur for a number of reasons. First, the missions of relevant agencies may not include matters pertaining to energy supply, and these agencies may have limited expertise or time to devote to project review. Second, federal agencies have historically not had a good track record of coordinating their reviews with those of other federal agencies or states, given their different statutory responsibilities and processes. Agencies may also wish to see what other regulators decide before making their own decision. While this may allow a particular agency to make a more informed decision, it is easy to see how wide adoption of a sequential approach can delay the overall review process. In addition, insufficient resources at some federal agencies may impede the timely and comprehensive review of projects. While some federal agencies, such as the USFS and BLM, have clear authority that enables cost recovery for siting reviews, other agencies with an important role in federal review, such as the U.S. Army Corps of Engineers or the U.S. Department of Agriculture's Rural Utilities Service, lack such clear authority.

EPAAct 2005 included provisions intended to foster improved conditions for siting transmission lines across state boundaries and federally managed lands. Most notably, the Act added section 216 to the Federal Power Act, providing FERC with limited backstop authority to issue permits for the construction or modification of transmission facilities in areas that had been designated by DOE as a NIETC.⁷¹ If state siting authorities withhold approval of a project in a NIETC for more than one year, FERC can issue a federal permit for the project if it makes specified findings. However, following a 2011 decision by the Ninth Circuit Court of Appeals that invalidated DOE's prior corridor designations, this backstop authority is not functionally available to FERC until new corridors are designated by DOE.⁷²

EPAAct 2005 also provided advance congressional consent to groups of three or more states to enter into an interstate compact to establish a regional transmission siting agency.⁷³

These agencies would have authority to site transmission anywhere in the participant states except on federal lands. States that are part of such a compact would also be largely immune from FERC's backstop siting authority. Despite some efforts to form regional siting agencies in the Midwest and West, however, this interstate compact mechanism has not been used.⁷⁴ From the perspective of state policy makers, surrendering their transmission siting authority to a regional entity may present the same risks of diminished autonomy as being subject to federal backstop authority.

With respect to siting transmission lines that require multiple approvals from federal land managers and other federal agencies, EPAAct 2005 sought to address the lack of federal agency coordination and transparency by designating DOE as the "lead" agency for coordinating environmental reviews of transmission projects that cross federal lands or otherwise require federal authorizations.⁷⁵ DOE must also coordinate "to the maximum extent practicable" with Indian tribes, multistate agencies, and state agencies.⁷⁶ In December of 2009, DOE and eight other federal agencies entered into a memorandum of understanding to coordinate transmission siting on federal lands.⁷⁷ The agreement provides that DOE will delegate the "lead agency" role to another signatory based either on the recommendations of the agencies involved or on which agency has the greatest land management interest.⁷⁸ For example, the U.S. Department of the Interior, and specifically BLM, is the designated lead agency for reviewing the SunZia Southwest Transmission Line,⁷⁹ a 500-mile line that will carry electricity generated in Arizona and New Mexico to major load centers in the Southwest.⁸⁰

The White House Council on Environmental Quality has also responded to transmission siting problems by initiating a pilot "Interagency Rapid Response Team for Transmission."⁸¹ The rapid response team initiative, which began with a focus on seven projects, seeks to coordinate scheduling among federal and state agencies, apply uniform approaches to tribal consultation, and resolve interagency conflicts.⁸² In addition,

DOE has created the “e-Trans” online tracking system to publicize information about each of its pilot transmission projects, including their current permitting status.⁸³

The politics surrounding siting are inherently complex, particularly in light of the fact that nearly all transmission siting decisions affect important local and state interests. But it is also the case that the ability to site appropriate interstate transmission projects in a timely fashion is essential to allow the grid to expand in ways that are economically and environmentally efficient while also successfully integrating clean energy resources, relieving congestion and associated costs, and ensuring reliability.

Recommendations

The task force applauds the focus on improving agency coordination reflected in EAct 2005, and the steps that federal agencies have taken to implement these coordination provisions thus far. Congress, the administration, and states should consider further reforms to siting procedures for projects that involve multiple jurisdictions. In particular, the task force recommends reviving a limited backstop authority at FERC with respect to state transmission siting reviews for interstate projects.

- **Congress should replace the existing backstop siting authority in § 216 of the Federal Power Act with a new, targeted backstop siting authority. In particular, this new authority should provide that FERC may grant a requested federal permit approving a multistate HVDC or 765+ kV AC transmission project within a state if: (1) the state siting authority (a) has denied the project without offering an alternative route that is consistent with relevant state law, or (b) has not issued a decision within 18 months of receiving a completed application, or (c) has insufficient authority to grant such an application; and (2) the project has been approved by a state siting authority in another state.**

Reform of the existing policy needs to strike an appropriate balance – maintaining state authority to protect consumers and environmental values, while ensuring that projects that provide broader regional or national benefits are not unduly impeded. The approach outlined below seeks to make backstop authority available only with respect to a narrow category of high voltage projects, and seeks to leave with states ample authority to oversee route selection and protect environmental resources.

This new, targeted backstop siting authority would be coupled with the repeal of the current authority in FPA § 216(a)-(b). It would not grant FERC any new authority with respect to the siting of transmission on federal lands. Where the proposed interstate line is also crossing federal lands, federal land agency approval would be required and the existing interagency coordination process would apply.

The key parameters for the targeted new policy would include the following:

Project Eligibility

- Only multistate HVDC projects and 765+ kV AC projects would be eligible. Eligible projects would no longer be geographically limited to DOE-designated NIETCs.
- The project must have been approved by at least one of the states in which it is to be located.
- A project developer could apply for a FERC-issued construction permit only if the developer had sought siting and construction approval from the relevant state regulatory body and such application had been denied without the state offering an alternative route that is consistent with relevant state law, or if the state body had failed to take action on the application within 18 months of receiving a complete

application, or if the state does not have authority to grant the application to the developer or to consider interstate benefits.

- o States would retain authority to require a route different than what was initially proposed by the developer without triggering the potential for backstop siting.

FERC Review and Implementation

- o As under current law, in order to exercise backstop authority, FERC would be required to find that the project is consistent with the public interest, is consistent with national energy policy, and benefits consumers. In making this determination, FERC should provide a presumption that the proposed project satisfies these prerequisites if it has been included for cost allocation within the relevant regional transmission plan(s) under Order No. 1000. For merchant projects, which are not required to participate in regional planning under Order No. 1000, FERC should consider the information provided by a developer to the relevant Order No. 1000-compliant regional planning process(es), and favorably consider a project if it has participated in the regional planning process to the extent possible in the applicable region(s).⁸⁴
- o States could be granted a special status in any FERC backstop siting proceeding whereby the appropriate state authority may recommend environmental conditions on a FERC-issued permit, and FERC must consider these conditions for inclusion and consult with state authorities before rejecting any state-recommended condition.
- o FERC should give due weight to any environmental record and siting results generated by the review process in the affected state, as well as any

information submitted to the state by the applicant as part of the review process.

- o If granted, a backstop permit would confer to the developer the ability to acquire rights of way via eminent domain.

- **States should review their transmission siting statutes, and consider updating them as necessary to ensure that state regulators have processes available to evaluate the merits of the full range of potential transmission projects, consistent with maintaining appropriate consumer and environmental protections.**

In many states, statutes governing transmission development and siting were enacted when the local vertically integrated utility was the only potential builder of transmission, and long before the business model of the merchant transmission developer had emerged. Such statutes may lack an avenue for state officials to consider projects proposed by an entity that is not already a utility in the state. State law may also preclude consideration of the regional benefits of a proposed interstate project in the state regulatory review process. Statutory constraints such as these may prevent development of projects that are in the public interest. Providing a state process for fair consideration of the merits of all proposed projects also eliminates one potential basis for the exercise of backstop siting authority (see recommendation above).

- **For multistate transmission projects, siting authorities in the affected states should collaborate to the extent possible to provide for timely and efficient review of siting applications.**

Improved coordination has the potential to reduce the time it takes to site interstate transmission projects and to lower the overall cost of such projects.

- **The administration should provide formal guidance clarifying that transmission projects, under specified**

conditions and where such development is not otherwise restricted (e.g., federal wilderness areas), represent an affirmatively encouraged use of federal lands, with important public benefits.

Such guidance might be supplied through an executive order or agency interpretative rule, if consistent with current statutes, or if required, via a statutory amendment (for instance, an amendment to the organic statute of a land management agency).

- **Federal and state agency leaders should consider executing memoranda of understanding to provide for coordinated reviews and timely approvals of particular projects or groups of projects.**

This model has been implemented with success in California. Specifically, in 2008 the Bureau of Land Management, the U.S. Fish and Wildlife Service, and several California state agencies entered into a memorandum of understanding to form a “Renewable Energy Action Team.”⁸⁵ The agreement committed the agencies to work together to ensure that California can access the in-state renewable resources needed to reach its ambitious renewable portfolio standard. This includes working together on a comprehensive Desert Renewable Energy Conservation Plan for the Colorado and Mojave deserts. When finalized, the plan will guide decisions about generation and transmission siting in the studied areas.

Similarly, the Western Governors Association has developed reforms to improve the transmission siting process across its member states.⁸⁶ A number of these reforms address issues of state and federal agency coordination such as the need for better coordination of state and federal review timelines.

- **Congress should provide federal agencies with the authority to recover costs incurred in the review of proposed transmission projects on federal lands in cases where the relevant federal agencies currently**

lack such authority, or where this authority needs to be extended or clarified because it is currently insufficient or unclear.

Federal agencies frequently face funding constraints that may limit their ability to devote sufficient resources to analyzing proposed projects or reaching out to stakeholders and other involved agencies at the federal and state level. Explicit authority to promptly recover costs should speed and improve the federal review process at agencies where cost recovery authority is lacking.

- **Federal agencies should improve internal accountability by designating specific senior officials at agency headquarters to be responsible for ensuring the timely review of proposed transmission projects.**

Agency permitting processes are often complex and may involve numerous staff members. This complexity may be unavoidable from the perspective of the agency, but results can be improved by clearly assigning leadership and direct responsibility for timely completion to a particular employee. This will create a sense of personal ownership of individual projects.⁸⁷ Assigning this role to a senior official located at agency headquarters will further improve efficiency by enabling better coordination with agency leadership.

“Right Sizing” of Transmission Lines

Given the considerable obstacles to siting, the cost of transmission projects, and the scarcity and value of rights of way, scaling transmission projects to serve only immediate capacity needs may often be an inefficient outcome. However, current economics of transmission development and existing cost-recovery practices can result in transmission projects that accommodate only currently planned or reasonably anticipated⁸⁸ generation capacity. The specific drivers that determine the size of a given transmission investment vary depending on the project type and market.

In regions with vertically integrated utilities, state regulators may be unable or unwilling to pass on to consumers the costs of uncommitted transmission capacity that may remain unused for an unknown period of time. Similarly, in ISO/RTO regions, stakeholders and regulators are likely to oppose any broad allocation of the costs of uncommitted transmission capacity, particularly if the transmission projects in question cannot be clearly linked to reliability benefits.⁸⁹ In both cases, the concern exists that approval of such costs will encourage developers to overbuild. Finally, in the case of merchant projects outside of formal transmission planning processes, financing may be jeopardized if the project lacks known subscribers for all or most of the new capacity being proposed. This can lead merchant transmission developers to downsize their projects to accommodate only the capacity needed by up-front subscribers.⁹⁰

Because of these market and policy conditions, the social and economic efficiencies associated with larger capacity transmission lines are frequently foregone. The result is a piecemeal approach to transmission expansion that is potentially more costly and environmentally disruptive.

Some states and ISOs have taken policy measures to encourage the transmission capacity additions that will be needed to connect future renewable generation to the grid, even ahead of firm generation capacity plans. For example, the Competitive Renewable Energy Zone (CREZ) program in Texas is designed to foster new transmission and renewable energy projects.⁹¹ The Public Utility Commission of Texas (PUCT) established five CREZs in areas where the PUCT anticipates that the addition of wind generation will create a need for significant new transmission investment.⁹² The PUCT then considered various transmission development scenarios for the CREZs and selected the most appropriate scenario in view of costs and projected needs.⁹³ Next, the PUCT implemented a competitive process to select developers to build the planned transmission, with costs recovered through socialized transmission charges.

Because most of Texas is not subject to FERC's transmission jurisdiction, state authorities have unusual unified authority to regulate with respect to transmission expansion, siting, cost allocation, and rates.

The California ISO (CAISO) provides another example. In 2007, CAISO adopted a "location-constrained resource interconnection" (LCRI) policy.⁹⁴ Under the LCRI policy, the costs of excess capacity built to serve future generators in transmission-constrained locations are recovered from all CAISO customers through a general transmission access charge, instead of being charged exclusively to the individual generator that is creating the need for new interconnection capacity. Other generators that subsequently build in the same area then pay for the share of the pre-built capacity that they actually utilize. In other words, the costs of the unsubscribed portion of the transmission facility are socialized until a generator emerges to purchase the capacity. One important distinction, however, is that the LCRI policy applies to interconnection facilities only; it does not extend to transmission projects more broadly.

Finally, the Midwest Independent Transmission System Operator (MISO) has defined a new category of transmission projects called "Multi Value Projects," which are transmission projects that would enable compliance with energy mandates such as state renewable portfolio standards, while also providing broader regional economic and reliability benefits. MISO has identified 17 such projects across its region⁹⁵ and, with FERC approval,⁹⁶ is broadly allocating the costs of the entire package of projects. While this approach is not specifically intended to enable "right sizing," it has helped clear the way for the Michigan Thumb Loop, a 140-mile, double-circuit, 345kV line that is intended to serve as the backbone for future wind development in the region.⁹⁷ This particular project also benefitted from a Michigan law that grants expedited siting approval to qualifying projects that would enable wind generation.⁹⁸ Under Order No. 1000, FERC specifically permits the grouping of transmission

projects into a package for purposes of cost allocation, provided that the facility costs allocated to customers are “roughly commensurate” with the benefits they receive.⁹⁹

Recommendations

- **FERC should issue policy guidance clarifying that regional transmission expansion plans may appropriately include – and provide cost allocation for – projects with capacity that will not be utilized immediately if such projects: 1) enable the efficient use of scarce rights of way, or 2) serve location-constrained generation, and the projects will provide regional benefits (including transmission access for future renewable development) over their lifetimes.**

In issuing this policy guidance, FERC should clarify that it may be just and reasonable to broadly allocate the costs of incremental capacity for expected future use in such a “right-sized” project. Once this capacity becomes utilized, cost allocation should be revisited to direct costs to beneficiaries.

By clarifying that such projects may be appropriately included in regional plans, FERC would increase the likelihood that project sizing decisions minimize consumer cost and environmental disruption from a long-run perspective.

Finally, as part of this guidance, FERC should encourage specific methods of right sizing – such as constructing double-circuit towers with only one circuit initially conductored – that reduce the overall siting impact of projects.

- **State PUCs should consider the environmental and economic benefits of right sizing transmission projects in siting and, if relevant, rate decisions on new transmission projects.**

Siting lines with some excess capacity may help to avoid new siting controversies and more costly projects in the

future. Knowledge that a state PUC is willing to consider cost recovery for right-sized transmission capacity in retail rates could ultimately help achieve policy goals by encouraging a more cost-effective build-out of necessary transmission infrastructure.

Upgrading Distribution Infrastructure

Appropriately, much attention has been focused recently on upgrading and expanding the nation’s transmission infrastructure.¹⁰⁰ However, in considering grid infrastructure policies, it is important to ensure that distribution system upgrades get their share of attention and investment. Many of the promising advanced grid technologies are implemented at the distribution level. Distribution automation, for example, offers important reliability and efficiency benefits. Expanding opportunities for demand response will require investments at the distribution level in many areas. The modifications necessary to accommodate two-way power flows from customer-owned distributed generation must be made at the distribution level. Changes to enable use of electric vehicles by expanding the ability of distribution systems to support a proliferation of charging stations will require investment. Certain types of energy storage could be implemented at the distribution level as the economics of storage improve.¹⁰¹ Finally, assuring cyber security could require substantial investments at the distribution level.¹⁰²

Distribution system investments are typically made by individual utilities subject to state regulatory oversight. Historically, investment in distribution infrastructure was relatively noncontroversial, and cost recovery relatively straightforward.¹⁰³ However, as the nature of distribution system investment changes to include technologies such as advanced meters, sensors, and control systems, the benefits of upgrades become more difficult to quantify, and will depend on the extent to which the utility can optimize management of power flows and integration of distribution-level resources. Given the uncertainty associated with such

investments, risk-averse regulators and utilities may in some cases delay or forego investments that would be efficient.¹⁰⁴

As penetration of advanced technologies (including smart grid communications and switching equipment, and behind-the-meter generation) increases on the distribution system, the distinction between transmission and distribution is likely to become blurred in some instances.¹⁰⁵ Traditionally, electricity distribution systems in the U.S. have been predominantly radial in nature, with a single, one-direction path from distribution substation to customer. However, advanced communications, sensors, and controls are enabling a shift toward a more networked topology at the distribution level in some regions. Increasing behind-the-meter generation will also lead to the increased potential for material reverse power flows. As distribution networks evolve to efficiently and reliably handle the increasing potential for two-way power flows from an increasing quantity of distributed renewable generation, as well as increasing quantities of demand-side resources, electric vehicles and energy storage, investments made at the distribution level may have broader implications for the regional transmission system. This evolution may create challenges for existing planning processes and cost allocation methods that will require new analytical tools, as well as improved information sharing between utilities, state and federal regulatory agencies, and regional transmission planners, in order to ensure that investments are optimized across the system.

Recommendations

- **State public utility commissions should share best practices on policies to encourage cost-effective modifications of distribution infrastructure for the integration of advanced grid technologies.**

Such a package of policies could be readily adopted in states and localities with sufficient enthusiasm for distribution-level modernization. DOE could fund a review of existing utility practices and PUC policies so that

best practices can be identified and shared. Possible vehicles for this process include a collaborative effort among state regulators (e.g., through NARUC), or a process implemented by an NGO with expertise in utility regulatory issues.

- **In implementing Order No. 1000, FERC should encourage increased coordination regarding the consideration of distribution-level investments in regional transmission plans if they have clear regional benefits to the transmission system. FERC, NARUC, state PUCs, transmission planning authorities, and utilities should collaborate to develop best practices for such coordination.**ⁱⁱⁱ

Where such coordination does not already exist, regional transmission planning processes should work with state and utility planning processes to ensure that cost-effective distribution-level investments with regional benefits to the transmission system are not overlooked. The development of best practices could draw upon the lessons learned from the DOE-funded EIPC and WECC planning exercises.

- **DOE, FERC, state PUCs, transmission planning entities, and utilities should consider new consultation and information-sharing approaches with respect to the interfaces of the transmission and distribution systems.**

Such consultation and information-sharing should help advance coordination on analysis and investment decisions, particularly as they pertain to transcendent issues such as cyber security and reliability. For example, DOE could offer recurrent information-sharing forums for states and/or regions, on topics that intersect transmission and distribution. Improving

ⁱⁱⁱ Not all task force members felt that this recommendation was necessary. Some felt that existing requirements to consider alternatives under Order No. 890 and Order No. 1000 are sufficient to encourage consideration of distribution-level investments, and that distribution-level investments are generally unlikely to have broader regional impacts on the transmission system.

analytical methods and tools available to policymakers and planners should be among the goals of such information-sharing exercises.

Should there be utility regulatory issues that would be informed by active coordination between transmission and distribution regulation, FERC and state commissions may benefit from greater cooperation. For example, at the request of a state PUC, FERC could consult with the state commission under section 209(b) of the Federal Power Act¹⁰⁶ so that the two commissions acting together could seek to coordinate on topics concerning the interface of the transmission and distribution systems. This approach would allow flexibility to address any unique regional issues on a region-by-region basis.



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Chapter 4: Advancing Planning and Operational Coordination across Jurisdictions

As electricity markets become increasingly integrated, it becomes correspondingly more likely that investment and policy decisions in one market will have implications for costs and operations in another market. Regional differences in market structure, policy priorities, and resource mix create considerable challenges for improving system reliability and integrating VERs. By the same token, a lack of coordination will unnecessarily increase the system costs of achieving clean energy and reliability goals.

With respect to planning, a number of efforts have begun to broaden the geographic scope of transmission planning. With federal grant funding under the American Recovery and Reinvestment Act of 2009 (ARRA), WECC and the EIPC have engaged in informational interconnection-wide planning exercises, including the development of a first 10-year WECC interconnection-wide plan in 2011 and a forthcoming 20-year plan in 2013.¹⁰⁷ FERC Order No. 1000, discussed in more detail below, creates new requirements for regional transmission planning and interregional transmission coordination. With Order No. 1000 still in the earliest stages of implementation as of early 2013, it is unclear what the impact of these requirements will be.

In addition, the physical reality that electricity flow cannot be restricted to market boundaries gives rise to operational challenges. As electricity flows across markets with different operating procedures and rules, “seams” issues have the potential to reduce the efficiency of the system and impose added costs on consumers.

This chapter considers policy options to improve coordination across regional markets and between regions and state planning entities in order to enhance overall system efficiency and reliability, and to address barriers to the integration of cleaner energy resources.

Interregional Transmission Planning and Operational Coordination

FERC oversees planning requirements for transmission providers.¹⁰⁸ FERC first identified specific requirements for transmission planning in Order No. 890, which was issued in 2007.¹⁰⁹ Under Order No. 1000, issued in July 2011, FERC expanded these requirements to establish affirmative requirements for regional transmission planning. Specifically, transmission providers must:

- Develop and participate in a regional planning process that produces a regional transmission plan;
- Consider state and federal public policy requirements in transmission planning;
- Develop regional cost allocation methods for transmission projects selected in regional transmission plans; and
- Coordinate with neighboring planning regions to develop procedures for coordination of planning and methods of cost allocation for interregional transmission projects.

While Order No. 1000 takes an important step toward rationalizing transmission development by requiring a regional planning process, it does not require the same planning activities for proposed interregional projects. Rather, Order No. 1000 requires adjoining regions to coordinate planning and negotiate cost allocation arrangements on a bilateral basis between regions. Such arrangements apply only to projects that straddle the two transmission planning regions.¹¹⁰ FERC has expressly declined to require interregional coordination for projects located entirely within a single region,¹¹¹ regardless of the interregional benefits of such a project. For example, a transmission project limited to one region could serve to enhance reliability in adjoining regions.

While Order No. 1000 takes important steps in requiring coordination of transmission planning between adjacent regions, more could be done to encourage regions to confront

some of the operational problems that arise at the “seams” between some regions. Seams issues arise from differences in market design, scheduling, and operating practices between regions. While some areas of the country have a history of strong coordination, additional coordination is necessary for others.

In regions where additional work is needed to address seams issues, key challenges include insufficient interregional coordination on transmission and generation outages; differences in the assumptions that underlie market modeling and planning; insufficient coordination on import/export pricing and scheduling; and different approaches to addressing the impacts of generation and transmission additions in adjoining regions. Suboptimal coordination on these matters can exacerbate loop flows¹¹² and result in disparate pricing and inefficient dispatch, cost shifting or inequities, and reliability concerns.

Finally, as noted above, the ARRA provided funding for initial efforts to explore interconnection-wide transmission planning.¹¹³ These exercises have focused on developing common assumptions and scenarios for assessing future transmission needs. However, it is not clear whether these interconnection-wide planning efforts will continue when the current funding runs out. The improvement of analytical methods and tools that support wide-area planning will be important to enable effective planning at broader geographic levels.

Recommendations

The task force offers the following recommendations:

- **FERC should consider providing further clarification and guidance regarding the specific interregional coordination requirements of Order No. 1000 so that industry compliance filings will better meet the commission’s objectives with respect to interregional coordination.**

This guidance should encourage neighboring regions to address, in their interregional coordination agreements, seams issues that may interfere with efficient power market operation. FERC could provide clarification and guidance in the form of a policy statement and address items such as information exchange on outage scheduling, conflict resolution, key matters in newly developed seams planning arrangements, and other specific minimum criteria that should be addressed as a part of the interregional coordination materials filed with the commission.

Where justified, FERC should provide guidance that is targeted to specific regions or groups of regions. For example, in the Western Interconnection, FERC could suggest that interregional plans include provisions for review by WECC to assure consistency in data and modeling assumptions. With respect to the seam between MISO and PJM Interconnection, FERC could provide direction as to the appropriate modification to the parties’ joint operating agreement.

- **Congress or DOE should consider providing funding for appropriate entities (e.g., WECC, EIPC, and the associated groups of states) to continue their voluntary interconnection-wide transmission analysis.**

Additionally, DOE should provide funding to improve analytical methods and software used in wide-area transmission analysis, and to support participation of a broader range of stakeholders in these interconnection-wide initiatives. DOE should also work with these planning initiatives to produce a set of lessons learned from their efforts.

Coordinating Regional Transmission Planning and Integrated Resource Planning

Order No. 1000 requires utilities that own transmission within a region to develop and implement a coherent process for regional transmission planning. The transmission planning process depends on critical inputs such as load growth rates, generation expansion and retirement plans, and penetration rates for demand response and distributed generation. One of the challenges for regional transmission planning processes, particularly in areas that are no longer served by vertically integrated utilities, will be the availability of good information on changes in the non-transmission elements of the electrical system. This information is important in order to assess the need for new transmission infrastructure and to analyze the potential contribution of non-transmission alternatives.¹¹⁴

Many states have some form of integrated resource planning (IRP) process in place. IRP is encouraged in the Public Utility Regulatory Policies Act (PURPA).¹¹⁵ In states with vertically integrated utilities, the IRP process is typically conducted by the utility itself, with oversight from the state PUC. Usually, the IRP process entails formulating long-term projections of electricity demand, identifying current and future supply resources (factoring in additions and retirements), modeling the impacts of new state or federal policies (such as renewable portfolio standards or emission standards), and then evaluating a range of new investments in generation, transmission, end-use energy efficiency, demand response, and other resources. The goal is to identify the least-cost plan for meeting projected demand, subject to reliability requirements, environmental standards, and other policy constraints.

In connection with utility restructuring, some states repealed or discontinued IRP in the early 1990s, and instead required utilities to file annual “procurement plans” with a shorter planning horizon and a focus on purchasing power.¹¹⁶ In addition, with the spread of restructuring, some states have moved to state-conducted, statewide energy planning. Other

areas have adopted region-wide approaches. The Pacific Northwest, for example, has a multistate energy planning process, as well as some utility IRPs.

Outputs from these resource planning processes, whether conducted by a state government, regional organization, or a utility, can have an important impact on transmission requirements. They can stimulate investment in end-use alternatives such as demand response that may improve the operation of existing transmission systems in a manner that defers or eliminates the need for new transmission or transmission upgrades; they may also identify a need for new generation resources, which in turn may require new transmission facilities.

Although FERC Order No. 1000 requires regional planning processes to take into account public policy requirements (presumably including state resource planning outcomes),¹¹⁷ and makes clear that its transmission planning requirements are not intended to conflict with IRPs,¹¹⁸ there is no mechanism for ensuring active coordination between regional transmission planning on one hand, and utility IRPs or state energy plans on the other. In areas served by vertically integrated utilities with IRPs, the analysis and consideration of distribution, generation, or other alternatives to local and regional transmission investments may occur as a matter of course. In other areas, however, decisions made by transmission planners may not be sufficiently responsive to the outcomes of state energy planning processes, and state and utility decision makers may fail to take into account the broader transmission outcomes that result from the regional transmission planning process. Successful coordination between regional transmission planning processes under Order No. 1000 and state- or utility-level planning processes can ensure that all parties have access to better information.

Recommendations

The task force believes that it would be beneficial to create more geographically and functionally coordinated planning

processes, and to ensure that regional transmission planners are fully considering the outputs from state and utility planning processes where such coordination across entities exists. Improved coordination will allow for better-informed decisions on new utility investments in transmission, generation and distribution assets; it will also allow utilities and transmission planners to consider and account for opportunities such as end-use energy efficiency, demand response, and distributed generation.

- **DOE should fund efforts to share best practices for coordinating utility IRP processes and state energy planning processes with related regional transmission planning processes.**

These best practices should address how the analytic assumptions used in utility and state planning processes could be coordinated with those used in regional planning, such that the same analytical work can be used for both processes and the outputs will be consistent. Likewise, best practices should attempt to reconcile the schedules for utility and state planning processes and regional transmission planning. This will allow for more efficient coordination and help ensure useful, timely results, especially given limited PUC and stakeholder resources. Documentation of best practices and dissemination of this information might be most effective if done under contract to DOE by organizations with a detailed understanding of state and utility planning processes.

- **Regional transmission planning entities should work with the states in their regions to better coordinate their analyses (e.g., planning methodologies, assumptions, and planning horizons) and the timing of utility and state planning processes so that the collective outputs of these efforts are as useful as possible to the regional transmission planning process, and vice versa.**

While this coordination might entail additional administrative efforts on the part of states, states would benefit from regional planning decisions that better reflect utility- and state-level planning outcomes.



Chapter 5: Enabling a More Flexible and Resilient Grid

Greater flexibility can enhance overall grid reliability and reduce the cost of VEG integration by reducing the need for reserve or back-up generators to support these resources. While fast-ramping thermal generation units and advanced transmission technologies such as flexible AC transmission systems (FACTS) are well known options for enhancing flexibility, flexibility can also be improved through demand response, energy storage, dispatchable distributed generation, and greater cooperation among utilities.¹¹⁹ Deployed successfully, these resources can

reduce the need for new generation or transmission facilities in some cases, thus avoiding or delaying the large capital costs and environmental and siting controversies inherent in building large new power plants or power lines. Advanced grid technologies, such as advanced metering and two-way digital communication, greatly enhance the potential of unconventional resources to provide system flexibility. Many of these technologies fall under the umbrella of smart grid systems, as seen in Figure 7.

Figure 7. Categories of Smart Grid Systems

Categories	Definition	Example Technologies
Integrated Communications	High-speed, fully integrated, two-way communication technologies that make the grid dynamic and interactive	<ul style="list-style-type: none"> • Wireless Communications Technologies • Home Area Networks
Advanced Components	Advanced components that play an active role in determining the electrical behavior of the grid	<ul style="list-style-type: none"> • Smart Switches, Cables, Transformers • Storage Devices • Grid-friendly, Smart Appliances
Advanced Control Methods	New methods and algorithms that monitor power system components, enabling rapid diagnosis and timely, appropriate response to any event	<ul style="list-style-type: none"> • Substation & Distribution Automation (Real-time Control / Monitoring) • Fault Locator Systems
Sensing & Measurement	Technologies that enhance power system measurements and enable the transformation of data into information	<ul style="list-style-type: none"> • Advanced Metering Infrastructure • Phasor Measurement Units • Dynamic Line-Rating Devices
Improved Interfaces & Decision Support	Interfaces that enable more accurate and timely human decision-making at all grid levels, including the consumer level, and more advanced operator training	<ul style="list-style-type: none"> • Software Tools to Analyze Electricity System Health • Distribution System Modeling Software

Source: Adopted from: "A Compendium of Smart Grid Technologies." National Energy Technology Laboratory and U.S. Dept. of Energy, Office of Electricity Delivery and Energy Reliability. 2009. http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/Compendium_of_Technologies_APPROVED_2009_08_18.pdf.

While there has been progress toward integrating these technologies, uncertainty over their potential benefits remains a challenge to widespread adoption. This chapter discusses recommendations for enhancing grid flexibility. It addresses distribution automation; dynamic pricing; market signals for demand response and energy storage; and research, development, and deployment for advanced grid technologies. Increasing cooperation across utilities and balancing authorities is discussed in Chapter 6.

Distribution Automation

Although the majority of line losses and customer interruptions occur at the distribution level, these networks tend to be the least instrumented and automated portion of the electric grid. As noted in Chapter 2, outages are estimated to cost businesses about \$79 billion each year in the United States.¹²⁰ Utilities can improve distribution system performance by deploying controllers and sensors in conjunction with a distribution management system to enable remote monitoring, and control and improve the integration of distributed energy resources. Distribution automation also provides the foundation for more advanced solutions including: volt/VAR control (VVC) to improve system efficiency through the coordinated management of voltage and reactive power flows; and fault detection, isolation and restoration (FDIR) systems that improve reliability by automatically reconfiguring distribution feeders when a fault occurs. Lastly, distribution automation solutions can leverage advanced metering systems to locate outages rapidly and target the dispatch of line crews, allowing utilities to restore service more quickly in outage situations.

Although many utilities have made some investment in distribution automation, traditional cost-of-service regulation may fail to value adequately the benefits of these technologies. Although regulatory models vary by state, the general cost-of-service model implies that regulators favor the least-cost investments necessary to meet standards for

service and reliability, with utility shareholders expected to bear the full risk of investment in advanced technologies. Under these circumstances, utilities face a disincentive to innovate as they prepare for new challenges such as higher levels of renewable and distributed generation, aging assets, and new load sources such as electric vehicles.

Distribution automation, and other innovative distribution-level technologies, would benefit from a new approach to ratemaking and cost recovery – one that balances shareholder risk with the potential for performance-based rewards. In some markets, such as the UK and Italy, policymakers and regulators have turned to output-based, incentive regulation to encourage utilities to make needed investments beyond those that simply achieve minimum reliability requirements. In the United States, Illinois recently launched a transition to an incentive-based regulatory model through its 2011 Energy Infrastructure Modernization Act.¹²¹ Beyond Illinois, however, most U.S. regulators and policymakers have been slow to recognize the value of alternatives to cost-of-service regulation.

Recommendations

- **NARUC should work with state PUCs to identify suitable output-based distribution system performance metrics that could be used in incentive-based regulatory proceedings. DOE should provide funding and support for this effort.**

These efforts should draw from experience with the ARRA's Smart Grid Investment Grant program and other ARRA programs to identify potential metrics related to reliability, availability, customer service, and system efficiency. As metrics are identified, DOE should fund NARUC and state efforts to develop model statutes or regulatory language for incentive-based regulation.

Advanced Metering Infrastructure and Dynamic Pricing

Advanced metering infrastructure (AMI) enables frequent two-way communication between retail utilities and their customers. Its operational benefits include automated metering, improved customer support, and more efficient management of distribution systems.¹²² A key non-operational benefit of AMI is the ability to communicate electricity price and consumption information to consumers at regular intervals, thereby creating a foundation for the implementation of dynamic pricing. Dynamic pricing allows prices to vary at frequent intervals, such as by hour, to reflect changing marginal production costs at different times of the day. This price variance provides an incentive for customers to make more efficient consumption decisions that reduce peak demand, thereby reducing or delaying the need for investments in new generation or transmission capacity.

State-level initiatives and grant funding made available under ARRA have allowed significant deployments of smart meters.¹²³ According to IEE, approximately 36 million smart meters had been installed as of May 2012; that number is expected to increase to 65 million by the end of 2015.¹²⁴ The expected deployment of smart meters by state up to 2015 is shown in Figure 8.

A recent MIT study found that the operational benefits of smart meters vary considerably across utilities, and that where operational benefits are low relative to costs, non-operational benefits are important to determining whether investments in smart meters are cost-effective.¹²⁵ The implementation of dynamic pricing is essential to achieve the full range of potential benefits from advanced metering. It will be important for utilities that are installing smart meters to establish a mechanism to make the granular, individual consumption data collected by the meters, along with time-based price information, available to the individual consumer in a comprehensive, understandable format, and in a

timeframe that allows the consumer to act on the information.

Although this mechanism is lacking in many areas, government and private entities have recognized this critical gap and have begun taking steps to bridge it. For instance, the 2007 Energy Independence and Security Act required that state PUCs consider adopting regulations requiring that customers be provided access to time-based wholesale and retail prices and usage information.¹²⁶ Likewise, ARRA grants have been issued to several utilities to undertake projects that improve customer access to energy consumption and time-variant price data.

To capture the potential benefits of widespread deployment of advanced metering systems, additional hurdles will have to be overcome. First, some state policymakers have been reluctant to embrace smart meters because they are wary of potential consumer opposition to the up-front cost of procuring and installing the hardware.¹²⁷ This concern may reflect a failure to account for the full non-operational benefits that smart meters offer.¹²⁸ In other cases, where utilities have recently installed automated metering infrastructure that lacks only the two-way communication capability of smart meters, installing new smart meters may not be cost-justified.

A second obstacle to the widespread adoption of advanced metering is the concern among consumers and state regulators that collecting granular information on individual customers' electricity use raises privacy issues. A 2010 DOE report entitled "Data Access and Privacy Issues Related to Smart Grid Technologies" summarized these privacy issues as follows:

Data about the energy use of a given household can be a powerful tool for increasing efficiency, troubleshooting, and lowering overall costs because each of the many household devices and appliances that consume electrical power tend to do so in a way that can enable a sophisticated analyst – given enough sufficiently granular energy-usage data – to identify the contributions

of particular appliances and devices to overall energy usage and to determine whether those contributions are consistent with those of an efficiently-operating appliance or device. The current state of the art, in terms of the granularity of data collected by utilities using advanced metering, cannot yet identify individual appliances and devices in the home in detail, but this will certainly be within the capabilities of subsequent generations of Smart Grid technologies.

Because such data can also disclose fairly detailed information about the behavior and activities of a particular household, ...the collection of [consumer-specific energy usage data] raises privacy implications that should be acknowledged and respected during the development of intelligent electrical-metering-and-usage-monitoring technologies. It is the energy usage data itself and the ability to tie that data to an individual or household that makes the data particularly sensitive.¹²⁹

Responding to the same concerns, NARUC has issued a resolution that supports the implementation of smart grid technologies like smart meters, but calls on its members to “take steps to provide that utilities, subject to State commission oversight, make cost-effective decisions while at the same time safeguarding their customers’ privacy.”¹³⁰ Likewise, the Obama Administration has issued a report that addresses the privacy implications of smart grids and concludes that “State and Federal regulators should consider, as a starting point, methods to ensure that consumers’ detailed energy usage data are protected in a manner consistent with [the Federal Trade Commission’s] Fair Information Practice Principles.”¹³¹

Resolving privacy concerns is important because smart meters offer unprecedented new opportunities for innovative third-party businesses that provide energy analysis and management systems, and demand response aggregation, with important potential efficiency gains for the system. Thus, while there is little disagreement about the importance of protecting

consumers’ privacy, customers should be permitted to authorize third parties to access their energy consumption data.

Recommendations

- **Utilities and state public utility commissions should offer dynamic retail pricing of electricity as an option where such rates are not currently offered and advanced metering infrastructure exists.**

Because dynamic pricing creates more accurate price incentives for electricity customers, it may go a long way toward making the demand side of electricity markets responsive to supply constraints, without the need for organized demand response programs. However, as described above, PUCs are likely to balance these benefits against their interest in shielding customers from price volatility and from the costs of more frequent price reporting. One approach is to provide customers with the option of time-of-use rates or dynamic pricing as an alternative to default rates, so that no individual customer is required to take service with variable pricing. Further, customers could be given real-time price information along with their conventional bill so that they can compare and decide which pricing structure would allow them to save the most in energy costs.

- **State legislatures or PUCs should ensure that customers are able to make their usage information available in a secure and privacy-protected format to third parties.**

While consumer-authorized access to usage information will be critical to cultivating a competitive market for customer-driven demand response technologies, its potential will be limited by the degree to which the information can be shared securely. Indeed, the entire concept of collecting energy consumption data with smart meters could be jeopardized if privacy concerns are not adequately addressed.

- **In states where utilities have installed or plan to install advanced metering infrastructure, state PUCs should require that utilities conduct consumer education and outreach.**

Education requirements should be consistent with NARUC's Resolution on Smart Grid Principles,¹³² which calls for comprehensive and funded consumer education programs. The utility, state PUC, consumer advocates, and appropriate third parties should be included in the development and evaluation of education and outreach programs.

Demand Response

The expansion of demand response programs offers significant potential economic and reliability benefits, including peak load reductions, improved system efficiency and flexibility, enhanced reliability, and avoided investments in new transmission and generation capacity. Demand response is an umbrella term that encompasses a variety of arrangements under which consumers (i.e., the “demand” side of the power market) intentionally reduce or increase (or agree to an adjustment of) their consumption of electricity in response to price signals or power grid needs.¹³³ Demand response comes in a number of forms and can serve a variety of purposes. Historically, the most common form has been “load management or control” programs, which offer customers reduced rates or incentive payments if they agree to reduce their “interruptible” load under certain conditions. A variation of this approach allows the load-serving entity to directly control customer equipment or appliances. This type of demand response is primarily intended to maintain reliability in the presence of stresses due to peak demand or loss of supply.

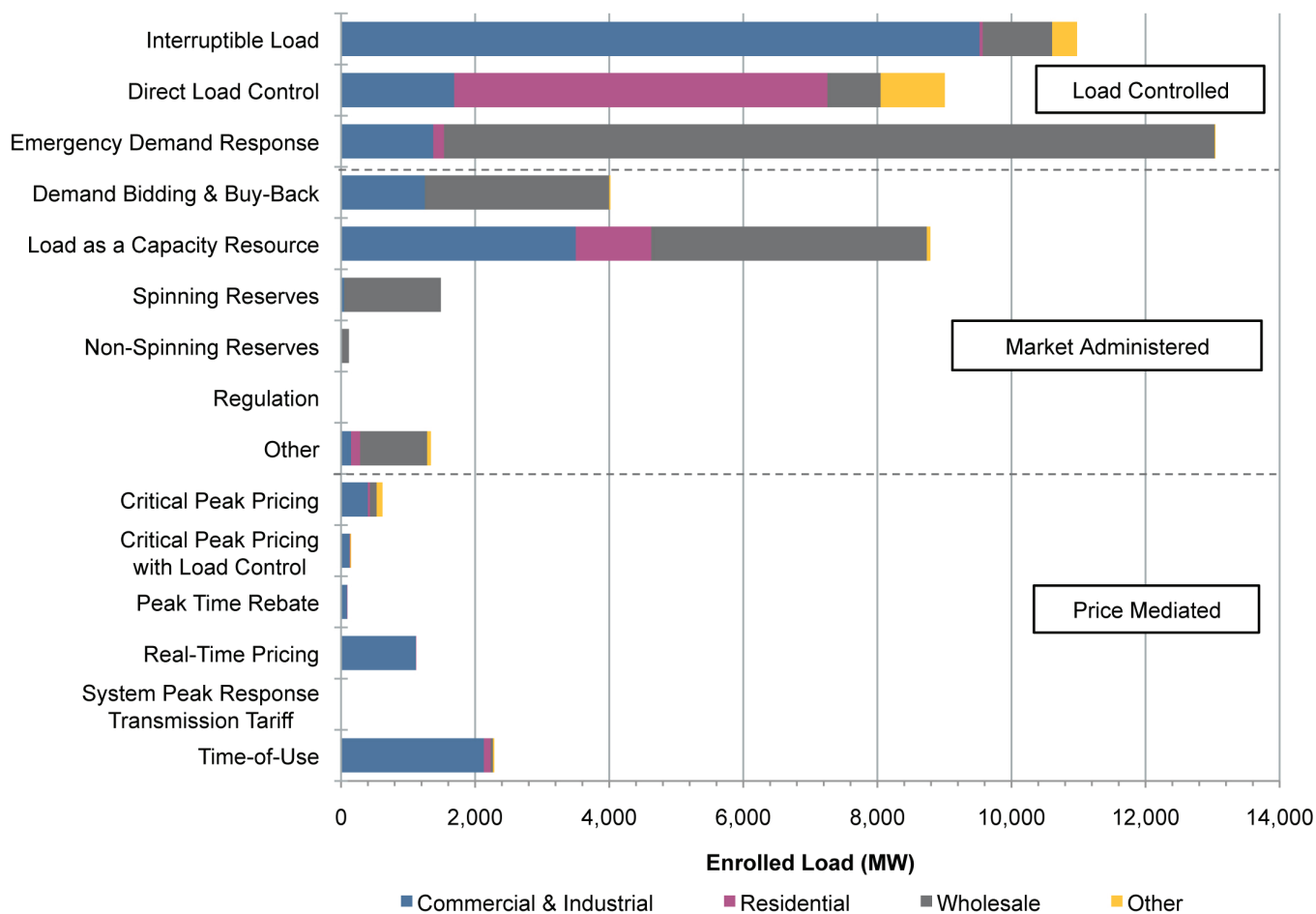
A second category of demand response consists of programs administered by organized wholesale markets. ISOs and RTOs have developed a number of ways to incorporate demand response into wholesale markets as a dispatchable

resource. These include allowing demand response to compete with conventional power plants as a capacity resource in forward capacity markets, offering demand buyback programs that allow customers to provide demand reductions at a specific price point, and allowing load to provide ancillary services such as spinning or regulation reserves. While such programs are generally most economic for large industrial and commercial customers, demand response aggregators have increased the participation of smaller customers, including residential customers.¹³⁴

The third category of demand response programs is price-mediated demand response. In these programs, customers face retail electricity rates that vary depending on the cost of electricity production at a given point in time, allowing them to reduce consumption when rates are high, or shift consumption to a time when rates are lower. These programs are well suited to reducing peak demand, which ultimately can reduce the amount of new capacity needed to meet reserve margin requirements. Currently, pricing for most end-use customers does not vary with the cost of production,¹³⁵ which mutes price signals and leads to inefficient consumption patterns. The most common form of price-mediated demand response is time-of-use pricing, wherein utilities provide a schedule of prices that vary over the course of the day and are known in advance to consumers. While this approach provides a more efficient means of pricing than purely flat rates, it does not actually track changes in marginal production costs in the manner that dynamic pricing does. By linking prices to actual production costs, dynamic pricing represents a more efficient approach than time-of-use pricing. FERC has summarized the potential peak load reduction from existing programs by program type, as shown in Figure 9.

While load management programs have historically accounted for the majority of demand response, the increasing penetration of technologies such as smart meters means that demand response opportunities, particularly

Figure 9. Enrolled Load by Type of Demand Response Program and Customer Class, 2010

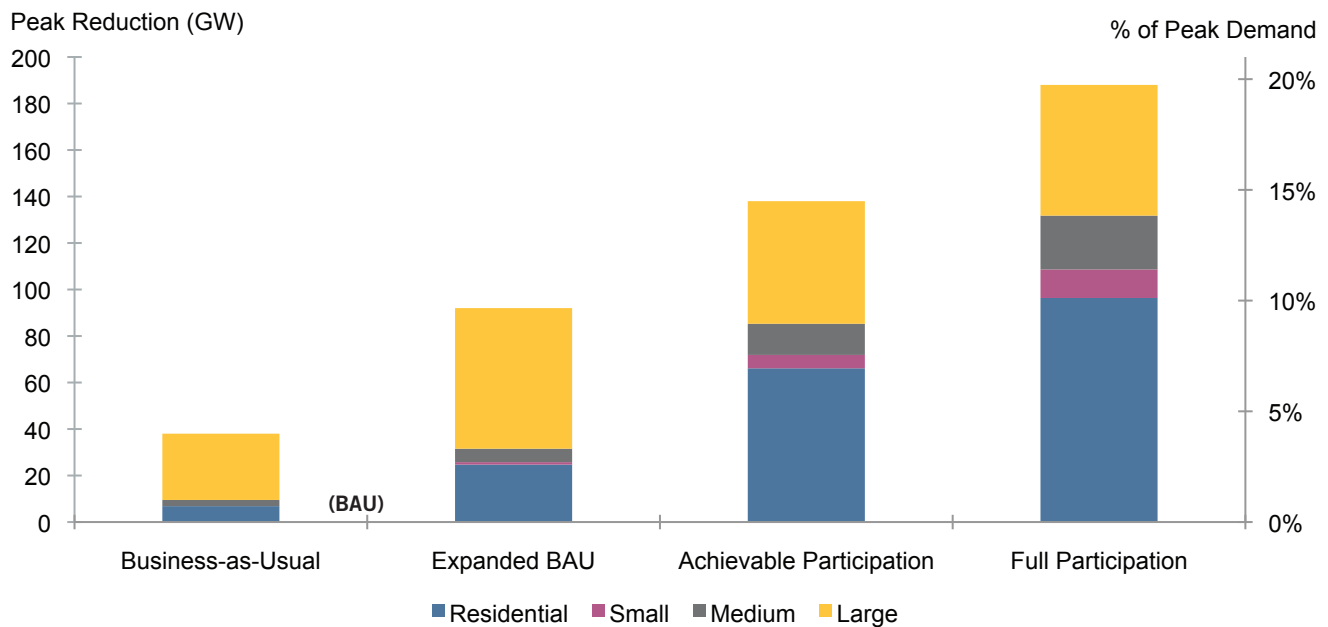


Source: "Assessment of Demand Response and Advanced Metering Staff Report." Federal Energy Regulatory Commission. (2011): 33. <http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf>.

in the residential sector, are growing substantially. In fact, a recent FERC assessment of demand response potential found that residential load offers the largest untapped demand response resource, as shown in Figure 10.

In all, introducing incentives to foster organized demand response programs, or to otherwise influence the demand side of the electric power sector, presents considerable

potential for lowering peak demand, improving system reliability, avoiding the need for investment in new generation and transmission, and accommodating planned retirements of generation facilities. Further, to the extent that loads are capable of being adjusted quickly and reliably, demand response could play an increased role in providing ancillary services such as regulation or contingency reserves, or other

Figure 10. Projected Demand Response Potential by Customer Class, 2019

Source: "A National Assessment of Demand Response Potential Staff Report." Federal Energy Regulatory Commission. (2009): 29. <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf>.

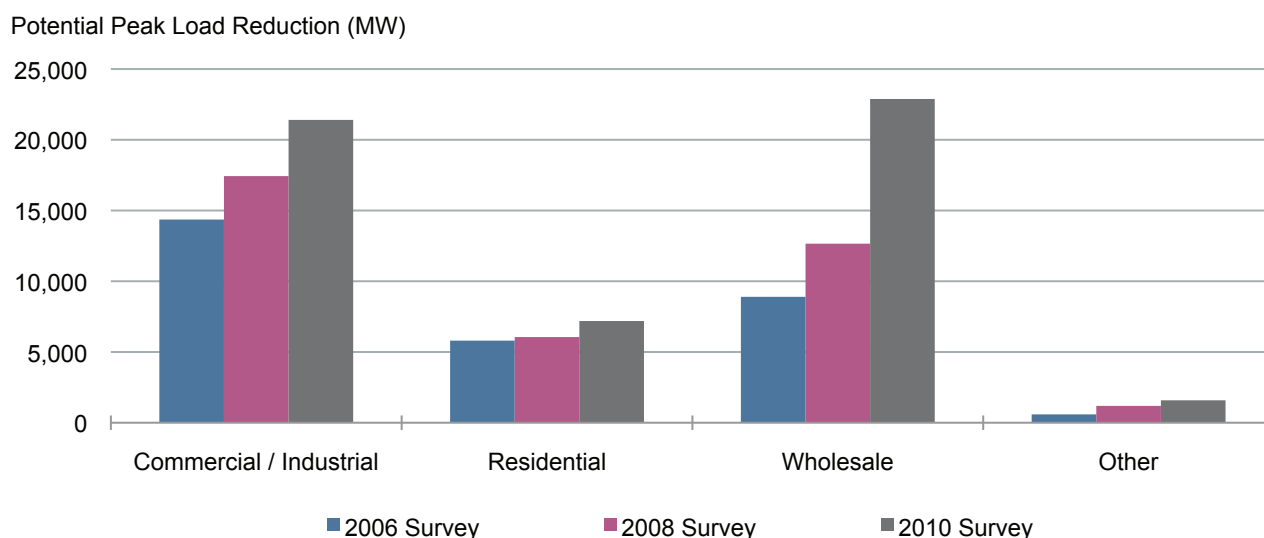
emerging flexibility products, thereby playing an important role in VER integration.¹³⁶

Demand response aggregation has moved past the experimental stage and is an important component of the portfolios of some markets. Figure 11 illustrates the steady increase in participation by demand response resources in recent years, and the significant growth of demand response in wholesale markets, where aggregators play a role in providing resources. PJM has been especially successful in encouraging participation of demand-side resources in its energy and capacity auctions, and recently established two new demand response services under its tariff.¹³⁷

Despite these recent developments, demand response as an active participant in energy and capacity markets remains a relatively recent development, and for a number of reasons,

not all RTOs and utilities are exploiting its potential benefits. First, state regulators may be reluctant to endorse dynamic retail pricing out of a desire to shield customers from high rates at times of peak demand.

Second, despite the importance of demand response in organized markets such as PJM, lingering questions remain about whether demand response aggregation is well suited to a major role in an energy supply portfolio, particularly where it includes agreements that do not allow the utility to directly adjust the load of the customer providing the demand response. The novelty of the resource creates concerns about whether the energy and capacity contribution it claims will actually be there when it is needed, i.e., whether customers who have committed to reducing their consumption on demand will actually deliver those reductions when they are called upon, particularly if they are called upon with some

Figure 11. Reported Demand Response Potential from Existing Programs

Source: “2010 Assessment of Demand Response and Advanced Metering Staff Report.” Federal Energy Regulatory Commission. (2011): 31. <http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf>.

frequency, as might be the case in especially hot summers or cold winters.

Third, demand response can present environmental quality concerns. Commercial and industrial customers may reduce their demand for grid services when requested, but compensate with on-site diesel generators. To the extent that demand response replaces electricity produced at centralized plants with electricity produced by dispersed diesel generators, there may be net negative environmental impacts. EPA recently issued regulations restricting emissions from on-site diesel generators, but has provided an exemption for those generators to participate in ISO/RTO demand response programs without controls for 100 hours per year. To the extent that this exemption gives uncontrolled on-site generators a cost advantage over conventional central station generators that have installed emissions controls, on-site generators may displace conventional generation sources, with a negative emissions impact.¹³⁸

Recommendations

The task force generally supports policies that will encourage the further active participation of demand-side resources in electricity markets. Because grid operators must be able to rely on this resource at times when the grid is under stress, programs that allow customers to opt out of load adjustment when called upon must be carefully managed.

- **Market operators and regulators should permit demand response resources, including demand response aggregators, that are capable of performing in a manner comparable to conventional generation to participate in electricity markets and auctions on the same terms as generation resources.**

Forward capacity markets and capacity auctions allow supply and demand resources to compete directly, and allow planners to make investment decisions informed by an understanding of the economics of new supply-side and demand-side resources.

Energy Storage

The current electrical grid incorporates very few facilities capable of storing electricity. Electricity storage is currently done at scale in some locations with pumped storage hydropower, though further development of this resource is constrained by the availability of suitable sites. Advanced storage technologies include grid-scale batteries, compressed air energy storage (CAES) systems, and flywheels. These technologies are not yet cost-effective enough to be adopted widely, but in recent years companies have successfully demonstrated utility-scale storage projects.¹³⁹ Electric vehicles (EVs) are often discussed as another potential storage technology, though applications may be limited.¹⁴⁰

Should storage technologies become cost-effective, a broad integration of energy storage facilities, accompanied by advanced grid technologies, would be a transformative development in the history of the electrical grid. In particular, it would enable new levels of flexibility by allowing the provision of fast-response ancillary services, and would facilitate the integration of intermittent renewable resources. In addition, it could potentially allow for significant load shifting, whereby energy would be banked during low-demand periods for later use during peak load periods. This practice could reduce the need to build new generation and transmission facilities.

Given the transformative potential of energy storage for the grid, as well as the high-risk and capital-intensive nature of related R&D, there is a strong argument for DOE leadership on advancing energy storage technologies. DOE currently maintains an energy storage program through the Office

of Electricity Delivery and Energy Reliability. The program conducts R&D on a wide variety of storage technologies including batteries, electrochemical capacitors, nano-structured electrodes, and others, as well as studies on the technical and economic performance of storage technologies. The program also collaborates with utilities and state energy organizations to field large pilot storage projects.¹⁴¹ In addition, DOE has provided \$185 million in matching funds to support 16 storage deployment projects. The Advanced Research Projects Agency-Energy (ARPA-E) has also conducted R&D on energy storage, providing \$115 million across a range of storage technologies over fiscal years 2010-2012.¹⁴² Finally, DOE established a Batteries and Energy Storage Hub in 2012. The hub is focused on overcoming critical technology barriers in energy storage while utilizing its links to industry to help bridge the gap between basic science breakthroughs and industrial commercialization.¹⁴³

In the meantime, energy storage has been subject to considerable regulatory uncertainty because the services it provides do not fit neatly into FERC's existing service categories: energy, transmission, and ancillary services. Storage, under various circumstances, could be viewed as providing any or all of those services.¹⁴⁴ To the extent that a storage facility is viewed as providing more than one service, there is the potential for cross-subsidization between uses (and between customers), and for double recovery.¹⁴⁵ In particular, there is concern that a utility could over-recover its costs by charging the costs of its storage facilities through cost-based rates, while simultaneously recovering costs by selling the storage services competitively through market-based rates.¹⁴⁶

FERC took steps to resolve some of this regulatory uncertainty in June of 2012 by proposing a rule to answer questions about the treatment of storage facilities under FERC's industry-wide, uniform accounting system. The rule envisions creating a new "storage" account in the "electric plant" (i.e., generation) category and amending two existing accounts

in the same category to create a total of three accounts for tracking investments in energy storage: production (i.e., generation), transmission, and distribution.^{147,148} In other words, FERC has recognized the multipurpose nature of energy storage and is attempting to allow those multiple functions to be treated separately.

Recommendations

The task force applauds DOE efforts to date on energy storage R&D, as well as FERC's effort to adjust its accounting rules to accommodate this nascent technology.

- **DOE should continue to emphasize energy storage in its R&D portfolio.**

Efforts should focus on technology breakthroughs that significantly lower costs. While the fiscal climate may call for cuts to overall federal R&D investment, the transformational potential of energy storage for the grid warrants sustaining and possibly expanding existing efforts.

- **FERC should continue to consider and clarify rate treatment for energy storage facilities.**

Further clarification of the regulatory treatment of storage technologies will be important to avoid discouraging investments in valuable new storage assets. In particular, it is important to ensure that a given storage facility can earn revenue for providing valuable transmission, ancillary service, and energy market services without inefficient regulatory barriers. In addition, given that there is likely to be a role for storage at the distribution level in the future, state PUCs should consider how rate proceedings might incorporate energy storage.

Research, Development, and Support for Advanced Technology Deployment

While there does not appear to be a fundamental gap in the basic research and development of advanced grid technologies, there are a few high-value and high-need areas for investment in research and development. These are technology areas where there are broad and potentially transformational system benefits that are unlikely to be captured by private actors, and where the incentives for private R&D investment are therefore suboptimal. Examples include improved analytical tools and software to support wide-area transmission planning (discussed in Chapter 4), energy storage (discussed in the previous section), and algorithms and software for aggregating and analyzing data from phasor measurement units (discussed in Chapter 6).

Despite significant progress toward integrating advanced grid technologies, these technologies continue to face deployment hurdles. For some technologies, such as advanced metering infrastructure, the benefits remain uncertain or unproven. Relative to investment in new generation capacity, as discussed in Chapter 3, investment in distribution-level technologies, or demand-side resources may be discouraged when PUCs perceive these technologies as unproven and costly. To counter this disincentive, government initiatives, including the ARRA, have funded advanced grid technology deployment projects, along with programs that offer guidance and technical expertise. DOE has also been collecting information and insights gained from these efforts, such as with its Smart Grid Information Clearinghouse.¹⁴⁹ Continued efforts to provide guidance and expertise, and to document lessons learned, should be a priority for DOE going forward.

Recommendations

DOE should continue to support the deployment of advanced grid technologies, and compile and disseminate lessons learned from these deployment efforts:

- **DOE should offer technical assistance, in the form of expertise and funds, to state PUCs (and municipal and cooperative utilities that are not state-regulated) that are interested in evaluating the costs and benefits, including the economic and reliability benefits, of advanced grid technology investments.**

In many respects, the policy and regulatory lead on advanced grid technology deployment resides with states, which have jurisdiction over issues of metering, distribution infrastructure, and retail rates. Therefore, one efficient way that the federal government can help to accelerate the implementation of advanced grid technologies is by supporting state and local efforts.

- **The DOE and FERC should provide guidance to regional transmission planning bodies with respect to modeling the impacts of smart grid and demand response investments on the transmission system.**

Regional transmission planning bodies are uniquely positioned to pursue certain important advances with respect to the smart transmission grid, including understanding the regional and interconnection-wide impacts of smart grid improvements at both the distribution and transmission levels.

- **DOE should produce a review of “lessons learned” from the numerous smart grid deployment initiatives that were funded under the ARRA, and should make the detailed data generated by those initiatives available to utilities and unaffiliated researchers.**

DOE, as the primary distributor of funds for smart grid applications under the ARRA, should continue to take steps to ensure that information gained through

experiences with those investments is captured for the benefit of future investors, policymakers, and researchers. DOE has taken a number of steps in this area, including the establishment of the Smart Grid Information Clearinghouse, as well as case studies of specific projects.¹⁵⁰ In addition, it has begun to identify approaches for analyzing the impacts of projects.¹⁵¹



Energy & Infrastructure Program
Energy Project



Chapter 6: Monitoring and Enhancing Operational Reliability

As described in Chapter 2, NERC, as the ERO certified by FERC, plays a lead role in setting reliability standards for, and assessing the reliability of, the bulk power system.¹⁵² NERC also establishes the conditions for balancing authority certification, which can have important implications for costs and reliability, particularly as penetration of VERs increases. Reliability of distribution systems, where most outages occur, is generally under the purview of states.

In practice, evaluating trends in grid reliability, particularly at the distribution level, can be challenging due to incomplete and inconsistent data. In addition, it is difficult to assess the extent to which reliability standards have led to measurable, cost-effective improvements in system reliability. This chapter describes ways to promote broader dissemination of reliability-related data, including the sharing of real-time operational data among utilities and grid operators. Further, it discusses recommendations to improve the assessment of reliability standards and the criteria for approving balancing authorities.

Understanding Trends in Reliability and Reliability Events

As the ERO, NERC is entrusted with developing reliability standards for a broad range of areas, including infrastructure security, resource and demand balancing, and transmission operation. NERC's proposed standards must be submitted to FERC for approval. Once approved by FERC, these reliability standards are binding on entities engaged in the bulk power system, including users, owners, and operators of generation and transmission facilities. NERC and FERC have promulgated and enforced mandatory reliability standards since 2007. Prior to that time, compliance with NERC standards was voluntary.

It is difficult to evaluate the extent to which reliability standards, individually or collectively, have improved bulk power system reliability. Historically, the lack of uniform,

consistent data on transmission system reliability made it difficult to analyze trends in the overall reliability of the bulk power system or to assess the effectiveness of reliability standards. A 2009 Congressional Research Service study noted that although NERC maintains detailed data on power plant reliability, "minimal data has been collected by government or industry on transmission system reliability."¹⁵³ Researchers seeking to evaluate trends in reliability have generally relied upon separate datasets on system disturbances collected by NERC and EIA. A 2009 working paper from the Carnegie Mellon Electricity Industry Center observed some inaccuracies and inconsistencies between the two datasets, but found them sufficient to evaluate trends in large blackouts.¹⁵⁴ A recent study from Lawrence Berkeley National Laboratory, however, cautions that key reliability metrics calculated from each dataset individually can vary significantly.¹⁵⁵

Over the last few years, however, NERC has taken steps to improve and expand data collection, metrics development, and analysis. NERC's 2012 State of Reliability report examines reliability trends over 18 metrics, including system voltage performance, bulk power system transmission events resulting in loss of load, transmission constraint mitigation, and transmission outages caused by protection system misoperations, human error or equipment failure, among others. The report also identifies the need for additional metrics to consider the reliability implications of non-traditional resources such as wind and demand response.¹⁵⁶

In order to provide for a common framework for reporting transmission system availability data, NERC developed the Transmission Availability Data System (TADS), which began reporting in 2008.¹⁵⁷ NERC has begun using TADS data to assess trends in reliability, and is also considering potential improvements and new metrics or applications.¹⁵⁸ NERC has used TADS data to summarize annual transmission outage statistics, to track trends in metrics associated with transmission availability, and to identify where more detailed

data are needed. For example, as shown in Figure 12, TADS data indicates that about 20 percent of sustained automatic bulk power system outages over 2008-2011 were caused by equipment failure. NERC has suggested that this finding warrants the development of more detailed reporting options for event causes to shed additional light on the nature of these types of events.¹⁵⁹

NERC maintains two other databases that address bulk power system reliability: the Generating Availability Data System (GADS),¹⁶⁰ and the Demand Response Availability Data System (DADS).¹⁶¹ Reporting for the latter began in 2011.¹⁶²

The prompt sharing of information from reliability events, including event analyses, lessons learned, and best practices, is an essential characteristic of a reliable electric system. However, utilities are generally hesitant to share potentially useful information with other utilities or system operators. In recognition of this potentially problematic dynamic, NERC began to undertake revisions to its Events Analysis Program in 2010, finalizing the separation of events analysis from its compliance audit and investigation process in 2012.¹⁶³

As described by NERC, “Event analysis is the aggressive critical self-analysis of BPS events that have occurred or have the potential to cascade. This analysis produces findings, lessons learned and best practices that provide experience-based insight to prevent repeat occurrences, provide informational material for entity training and industry learning, and institutionalize knowledge.”¹⁶⁴ While the emphasis is on self-reporting and analysis, for the most severe reliability events, either NERC itself or the relevant regional reliability organization leads the analysis.¹⁶⁵ NERC and FERC staffs have collaborated to produce three detailed reports on the engineering and technical causes of, and lessons to draw from, three recent significant reliability events.¹⁶⁶

With respect to compliance and investigations, EPAAct 2005 authorized substantial civil penalties for violations of reliability standards. Penalties may be imposed as a result of compliance

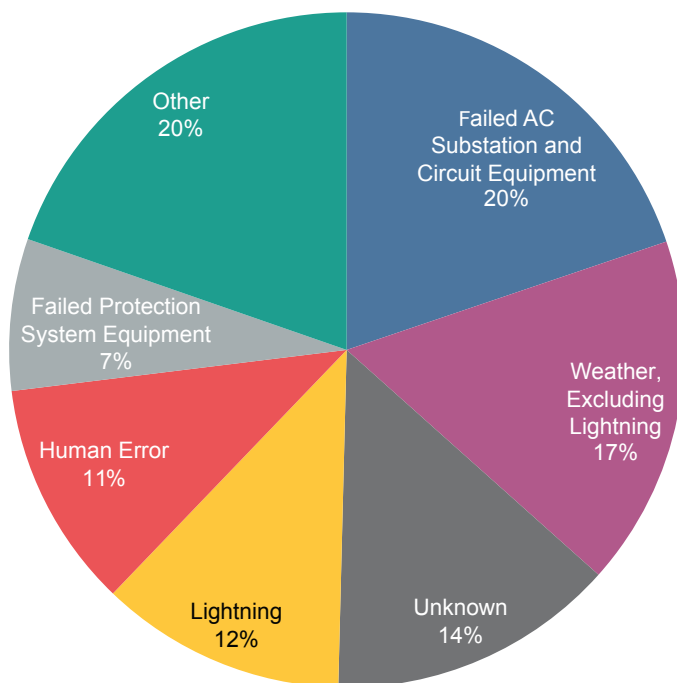
audits and investigations. Although such compliance reviews may produce helpful insights and lessons learned, they are usually resolved through settlements or abbreviated public notices that do not publicly describe all the facts surrounding the compliance violation and thus may limit their value to other utilities. For example, a significant Florida blackout in 2008 precipitated a joint NERC-FERC investigation, which concluded with a \$25 million settlement with Florida Power and Light.¹⁶⁷ The commission’s order approving the settlement did not identify the specific standards that Florida Power and Light violated in connection with the blackout.¹⁶⁸

At the distribution level, where the vast majority of outages occur, the availability of standardized data is a much greater challenge. Distribution system reliability is typically under the regulatory purview of state PUCs. As of 2008, only 35 state PUCs required utilities to routinely report information on reliability events, and 37 state PUCs made the reliability information collected from utilities publicly available in some form.¹⁶⁹ In addition, reporting requirements and practices vary enough across states to make comparisons of reliability across states and regions difficult.¹⁷⁰ The variation in state reporting requirements also makes it difficult to extract information on the causes of specific reliability events. This is especially true with respect to short outages, such as those triggered by lightning strikes.¹⁷¹

Recommendations

At the bulk power system level, NERC has begun to make important progress in collecting and making available detailed reliability-related data, and should continue to expand those efforts. At the distribution level, insufficient and inconsistent data availability remains a significant challenge to assessing and improving reliability. Finally, at both levels of the grid, there is a need to further encourage prompt sharing of information related to individual reliability events. Improved reliability-related data and analysis can enable the electric power sector to learn from past reliability events and anticipate and plan for future reliability events.

Figure 12. NERC 2008-2011 AC Circuit Top Ten Sustained Automatic Outage Occurrences by Cause



Source: “2012 State of Reliability.” North American Electric Reliability Corporation. (2012): 10. http://www.nerc.com/files/2012_SOR.pdf.

Note: Percent is out of total number of outages. Other includes fire, vandalism, terrorism or other malicious acts, failed AC/DC terminal equipment, failed DC circuit equipment, vegetation, environmental, contamination, foreign interference, or power system conditions.

Given the instructional value of such data for utilities, the public, and federal and state regulators, the task force offers the following recommendations:

- **NERC should continue to devote resources to improving transmission-related reliability data, and assess the value of information generated in TADS, as well as remaining data gaps. NERC should also continue to improve its Event Analysis Program and the process for developing and disseminating lessons learned from reliability events.**

As NERC continues to develop TADS, efforts to ensure that it is as comprehensive and instructive as possible will benefit future reliability. NERC has improved its process over the past two years to expedite the review of significant outages. NERC should continue to work with groups such as the North American Transmission Forum in order to review lessons learned with registered entities.

- **FERC and NERC should consider whether potential civil penalty liability is an obstacle to sharing valuable information arising from non-compliance with reliability standards.**

If civil penalties are found to impede information sharing, FERC and NERC should seek input from stakeholders on how to best mitigate this obstacle.

- **NARUC should encourage state PUCs to establish common standards and definitions for compiling and reporting detailed distribution-related reliability data.**

Reporting requirements for outages vary considerably across states. Given that the majority of outages are related to incidents at the distribution level, more detailed reporting using common standards and definitions would provide important knowledge of the causes of such outages and an understanding of broader trends at the distribution level, and would also create opportunities for information sharing and learning across states. The IEEE standard that has been adopted in some states should be evaluated for consideration as a model standard.

- **NERC and state regulators should ensure that outage data is made available to researchers and the public, subject to appropriate protections for critical energy infrastructure information.**

Independent researchers bring a valuable perspective to the study of reliability. Further, providing public access to understandable outage data will allow customers to compare performance between their utility and other similarly situated utilities.

Prioritizing Cost-Effective Reliability Standards

One notable limitation of the current process for developing new reliability standards is the absence of any explicit consideration of implementation costs relative to reliability benefits. Neither NERC nor FERC is under any statutory or regulatory obligation to account for cost-benefit considerations in developing reliability standards. Consequently, neither NERC nor FERC explicitly applies cost-benefit principles, or thoroughly evaluates economic impacts on consumers, when formulating and approving reliability standards. Many task force members believe that there are at least some reliability standards that impose significant costs but yield uncertain reliability benefits. Currently, operators are subject to reliability standards covering everything from transmission operation to personnel training. It is not clear that this large collection of standards, each of which requires operator resources to ensure compliance, allows either regulators or operators to prioritize the most important reliability measures.

In order to develop recommendations for improving NERC's standards development process, NERC's Board of Trustees initiated a Standards Process Input Group. Draft recommendations from the group, released in April of 2012, emphasized the need for consideration of costs, benefits, and justification for all standards.¹⁷² A key recommendation, which NERC has already implemented, was the creation of a Reliability Issues Steering Committee (RISC), which reports to the NERC Board of Trustees on priority reliability issues. An expected benefit of the RISC is greater efficiency of the NERC standards program, including recommending reliability solutions other than new standards where warranted.¹⁷³

In addition, in May of 2012, NERC proposed a "Cost Effectiveness Analysis Process" (CEAP), which will explicitly incorporate cost-benefit concepts into NERC standard development. The CEAP proceeds in two steps, the first of

which is to consult stakeholders to "determine the relative cost impacts (in orders of magnitude) of a particular proposed course of action,"¹⁷⁴ or the overall feasibility of the standard. Next, there will be a more detailed "Cost Effectiveness Assessment" to "determine the estimated industry-wide cost impacts (implementation, maintenance, and ongoing compliance resource requirements) and potential reliability benefit of requirements in a proposed draft standard."¹⁷⁵ The final cost-effectiveness assessment will be reviewed by NERC's Board of Trustees as it considers whether to approve the proposed standard.

Recommendations

The task force commends the recent effort by NERC to examine the cost effectiveness of its reliability standards and offers suggestions to help further the influence of such considerations on reliability regulation. In addition to establishing a process for consideration of costs and benefits of individual standards, the task force recommends that NERC and FERC develop a shared view on how cost-benefit analysis is to be considered, so that NERC can appropriately prioritize its standard-setting activity based on the potential reliability enhancement versus the projected cost to customers.

- **NERC should implement, and FERC should support, formal cost-benefit analysis as part of the standards development process.**

NERC's proposed CEAP may be a good first step in this direction. FERC should consider whether and how it should weigh the costs of implementing proposed standards and the expected benefits in reviewing NERC-proposed standards. Cost-benefit analysis should properly account for the low probability yet high consequence nature of the extreme reliability events that are the impetus behind certain standards.

- **NERC could usefully apply cost-benefit analysis to existing standards as well, to guide decisions on whether**

to modify (or eliminate) existing standards, or whether to adjust enforcement priorities to focus on compliance with standards that have the greatest public benefit.

Because NERC's standards currently in effect have never been subjected to a formal cost-benefit analysis, NERC could further the influence of its recent focus on cost-benefit analysis by reviewing some of its existing standards retroactively. However, such a review should also consider the cost of repealing the standard, to the extent that it is already in effect.

Increasing Data Sharing from Monitoring Systems

The increasing deployment of advanced grid monitoring technologies, such as phasor measurement units (PMUs), offers the potential to improve the ability of grid operators to monitor threats to reliability and understand causes of reliability events. In contrast with prevailing technology, which measures power flows approximately every four seconds, PMUs measure flows 30 times per second, and time-stamp the information.¹⁷⁶ Time-stamping the measurements from a PMU allows synchronization with data from PMUs owned by other entities, potentially providing grid managers with a coherent picture of the circumstances across a wide area of the electric grid.

PMUs offer several specific reliability benefits. First, they enable grid managers to operate the grid with greater precision, and to more quickly diagnose reliability problems like brownouts. Real-time sharing of operational data from PMUs could allow many significant reliability events on the bulk power system to be avoided. Information from PMUs can also greatly enhance post-hoc investigations of grid failures. Further, a wide deployment of PMUs can help grid managers anticipate and accommodate variable generation from renewable resources.¹⁷⁷ As NERC has explained, the “[v]isibility of power system dynamics is becoming even

more critical as the power system grows with inclusion of more variable resources.”¹⁷⁸ Finally, PMUs can enable real-time transmission path ratings, thereby increasing transfer capabilities on existing paths while protecting reliability.

Capturing the full range of benefits from PMUs, however, requires broader deployment, the appropriate software to aggregate and analyze collected PMU data, and willingness of entities to share the data collected. Given the broader system benefits of software for data aggregation and analysis, there is a strong argument for federal government support of R&D in this area, as individual utilities or technology vendors are unlikely to invest sufficiently in R&D for this purpose.

With respect to broader deployment and data sharing, federal policy has provided some progress. DOE has provided funding in support of extensive PMU deployments. There were approximately 250 PMUs deployed in North America in 2010; cooperative projects under the ARRA Smart Grid Investment Grants program were expected to increase that number to over 1,000 by 2012.¹⁷⁹ FERC has required information sharing with DOE's Smart Grid Information Clearinghouse as a condition of rate base recovery for PMUs and other advanced grid technologies.¹⁸⁰ In addition, NERC has created two nondisclosure agreements in order to encourage the sharing of PMU data across regions and with researchers, though only a limited number of entities have signed these agreements thus far.¹⁸¹

The sensitive nature of the data collected, the perceived liability risk associated with sharing operational data with regulators, and the historical industry practices in some regions (e.g., the Western Interconnection) all pose challenges to data sharing. That said, the West has recently implemented a broad data-sharing agreement with 98 percent execution among transmission owners, operators, and balancing authorities, though it does not provide for data sharing with market operators. The agreement covers data collected by PMUs as well as other operating reliability data.¹⁸²

The task force applauds DOE's aggressive funding support for PMU projects, as well as FERC's efforts to proactively establish guidelines for utilities to recover the costs of PMU installations.

Recommendations

Given the wealth of information that PMUs produce, and the potential value of that information for forensic purposes, the task force recommends further steps to ensure that the full range of benefits from PMU data is captured.

- **DOE should provide research funding for the development of algorithms and software that can aggregate and analyze PMU data.**

Such software would enable the sharing of information generated by PMUs for operational and planning purposes. Given the broadly dispersed benefits of such software, it is unlikely that individual utilities or technology vendors will sufficiently invest in its development on their own.

- **NERC should require the real-time sharing of PMU data and other operational reliability data among transmission owners and operators, balancing authorities, reliability coordinators, and market operators. Appropriately time-lagged data should be shared with unaffiliated researchers.**

To fully enjoy the informational benefits that PMUs can provide, their granular data must be made available to fellow utilities and system and market operators. However, information-sharing practices involving non-government entities must incorporate appropriate protections to address security concerns. Data-sharing agreements or a FERC order directing such data sharing should ensure the protection of sensitive information.

Promoting More Efficient Balancing Authorities

Balancing authorities, which are charged with balancing electricity supply and demand over their footprint, play an essential role in maintaining electric system reliability. Like other important features of the electric grid, the geography of balancing authorities has evolved organically, with balancing authority areas often determined by the service areas of particular load-serving entities. Balancing authorities vary significantly in size, in the portfolio of generation serving their load, and in the extent of their operating reserves. New York and ERCOT (i.e., most of Texas), for example, each have a single balancing authority, while within the WECC there are 38 balancing authorities. While most balancing authority areas have a mix of resources, some are limited to single resources or generation units. For example, the NaturEner Power Watch, LLC balancing authority in Montana consists entirely of a 210 MW wind facility. Although balancing authorities play a crucial role in maintaining the day-to-day reliability of the electrical grid, their territories have been defined without a particular focus on optimizing some of the critical elements of reliability. Balancing authority areas that are insufficiently large or diverse are ill-equipped to compensate for unexpected variability in generation or load.

NERC administers the process through which balancing authorities are established, although NERC may delegate this function to regional reliability entities like WECC, subject to NERC's requirements. While the balancing authority certification process involves significant scrutiny of the proposed balancing area's ability to comply with NERC reliability standards – including a site visit by NERC representatives – balancing authority certification requests are approved when the applicant meets minimum reliability standards. In other words, the process does not focus on whether the proposed balancing authority area is economically justified, nor does it take into account regional circumstances or grid-wide reliability impacts.

The resulting ad hoc nature of balancing authority areas has introduced the problem that many balancing authorities lack the size and resource diversity to operate efficiently. The efficiency and reliability benefits of greater cooperation or consolidation are magnified where integration of a significant quantity of VERs is expected. By increasing resource and load diversity, geographically broader markets mute the impact of variability from intermittent resources. WECC is in the process of conducting a study on the benefits of balancing authority consolidation within its footprint. Thus far, the council has found that for a scenario in which wind and solar penetration is equal to 11 percent of demand, balancing area consolidation would result in annual savings between \$400 and \$600 million due to reduced output from thermal units, and would result in a 50 percent reduction in reserve needs.¹⁸³ Similarly, recent modeling of a proposed energy imbalance market in the West found that the proposed market would reduce annual electricity production costs by \$146 to \$300 million.¹⁸⁴ The Southwest Power Pool (SPP), which has been operating an energy imbalance service for multiple balancing authorities within its region for several years, has found annual benefits on the order of \$100 million.¹⁸⁵

Of course, consolidation of existing balancing authorities or movement toward integrated imbalance markets involves implementation and other costs that may be overlooked by modeling exercises. For example, SPP incurred start-up costs of \$40 million in the development of its Energy Imbalance Services market, and annual implementation costs have been about \$20 million, though these numbers are much lower than the \$100 million in estimated annual benefits.¹⁸⁶ Another potential impact of balancing area consolidation is cost shifts, which can arise if generation constructed to serve one utility's customers (and paid for by those customers) is dispatched to serve another utility's customers. Finally, transitional reliability issues may result if flows in the newly consolidated balancing authority deviate from how the transmission system was originally planned.

Recognizing the potential cost savings and reliability benefits, many areas with abundant wind and solar resources have shifted toward greater balancing area cooperation and the formation of geographically broad energy imbalance markets. With the exception of California, however, this has generally not occurred in the West.

Recommendations

The task force believes that NERC and FERC should take steps to ensure that balancing authority design is efficient, and that small or insufficiently diverse balancing authorities do not increase the costs of integrating VERs.

- **NERC and FERC should review and modify the criteria governing the establishment of new balancing authorities to require the explicit consideration of the costs to consumers and impacts on reliability, including the costs and impacts associated with integration of variable energy resources.**

Balancing authorities are the building blocks of electric reliability, and their geography may have important implications for the ability of the system to integrate VERs efficiently. FERC, NERC, and the regional reliability entities should ensure that the configuration of any proposed new balancing authority supports both reliability and the efficient integration of VERs. In addition, upon request by a state PUC, LSE, balancing authority, or another entity with reliability management responsibilities, NERC should fund a study to assess the potential benefits of balancing area consolidation in the requesting region. In the West, where there are a number of small balancing authorities and a relatively high concentration of VERs, FERC and WECC should consider whether existing balancing authorities are effectively configured to promote system reliability and minimize the costs to consumers of integrating renewable resources. To the extent that they are not, FERC and WECC should recommend consolidation where appropriate.

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- **When evaluating whether a transmission provider's proposal to charge variable energy resources for ancillary services under an Open Access Transmission Tariff is just and reasonable, FERC should consider whether the transmission provider has taken reasonable actions to minimize integration costs.**

Under FERC policy, transmission providers may seek authority to charge VERs for a new generator regulation and frequency response service. In reviewing such applications, FERC should consider whether the transmission provider has taken advantage of opportunities to cooperate with other balancing authorities to minimize the cost of providing such service, through such measures as dynamic scheduling or regional balancing markets.



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Chapter 7: Conclusions and Next Steps

Changing economic conditions, energy markets, and energy and environmental policies mean that the U.S. electric power sector is entering a period of transition. A key part of that transition – the deployment of cleaner energy resources – is likely to accelerate over the next decade. This task force has identified a number of policy options aimed at enabling the integration of cleaner energy resources, including VERs, in a manner that is efficient and that also enhances system reliability. Four broad policy goals provide the focus for the task force’s recommendations:

- Encouraging efficient transmission and distribution investment
- Advancing planning and coordination across jurisdictions
- Enabling a more flexible and resilient system
- Monitoring and enhancing operational reliability

Given that federal, state, and regional organizations all play an important role in governing and managing the U.S. grid, the task force’s recommendations address institutions at all three levels, while targeting individual recommendations to the specific entity most suited to implementing them based on current jurisdiction and expertise. Given the diversity of market structures and policies that characterizes the U.S. power sector, not all recommendations will apply equally across the country.

A few broad themes emerge throughout this report. One is the potential value of improved data in creating a more efficient system. For example, better data on system reliability can inform investments in reliability upgrades and improve the effectiveness of reliability standards. In particular, sharing information from PMUs is essential to more effectively monitor and understand system reliability. On the demand side, providing customers with actionable information from smart meters is essential to achieving the efficiency benefits from dynamic pricing; allowing customers to share the information securely will be

necessary to expand the potential of demand response.

A second major theme is the need for greater cooperation among state, federal, and regional institutions. In the context of transmission siting, for example, cooperation among state agencies and, when relevant, federal agencies, can make the siting process more efficient and provide opportunities to resolve conflicts. Similarly, cooperation between states and regional transmission planning entities will be essential to ensure that regional transmission plans are consistent with state energy plans and other state policy goals. DOE and FERC can play an important role in providing technical assistance to state PUCs and other relevant state agencies as they seek to evaluate possible investments in advanced grid technologies. These examples represent only a few of the areas where significant potential for improved cooperation has been identified.

A third theme is reducing obstacles to investments that can support the efficient and reliable integration of cleaner energy resources. For example, reducing challenges to transmission siting and right sizing can help clear the way for the transmission investments that will be necessary to integrate VERs on a larger scale. Improving knowledge on the costs and benefits of advanced grid technologies can reduce the uncertainty that may deter such investment and increase the ability of utilities and state regulators to identify beneficial technology investments.

A final theme across the recommendations is providing value to customers and avoiding unnecessary costs. For example, in the context of reliability standards, consideration of costs and benefits can allow NERC to prioritize reliability standards that provide significant benefits to the system, while potentially eliminating those that impose costs in excess of benefits. In the context of transmission investment, providing cost recovery mechanisms for appropriately right-sized projects can avoid a piecemeal pattern of investment that is ultimately more costly. Finally, providing greater market

access for resources such as demand response, efficiency, distributed generation, and storage will allow these resources to compete as potentially more cost-effective alternatives to new transmission and generation investment.

In the coming months, the co-chairs and members of the task force will reach out to policymakers and stakeholders to advance these recommendations. In addition, given the importance of cyber security to a safe and reliable electricity system, BPC plans to address cyber security issues for the grid in 2013.

Statement from NARUC

The National Association of Regulatory Utility Commissioners staff was pleased to participate in this project as a resource to the BPC Electric Grid Initiative. While NARUC commends the Bipartisan Policy Center for the quality and scope of this report, we do not endorse any of the recommendations included. As an Association, NARUC sets its policies through resolutions. Several of the policies in this report are consistent with existing NARUC resolutions; others are not, and on some recommendations we do not have existing positions. In addition, as noted above, NARUC strongly opposes the recommendation calling for the expansion of the federal government's authority to site transmission facilities. This position is based upon NARUC's March 2009 policy resolution restating the Association's longstanding opposition to the enactment of legislation that would expand Federal siting authority.

http://www.naruc.org/Resolutions/2009Transmission%20Resolution%20as%20Adopted%20by%20the%20Ex%20Com%20_2_.pdf

Endnotes

1. The Eastern Interconnection serves the majority of load subject to NERC jurisdiction. For example, the Eastern Interconnection represented 74 percent of total projected NERC internal demand for summer of 2011, and the Western Interconnection and ERCOT represented 17 percent and nine percent, respectively. “2012 Long Term Reliability Assessment.” North American Electric Reliability Corporation. (2012): 46. http://www.nerc.com/files/2012_LTRA_Final.pdf
2. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services*. Final Rule, 75 FERC ¶ 61,080 (1996) [hereinafter “Order No. 888”]. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp>
3. *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*. Final Rule, 75 FERC ¶ 61,078 (1996) [hereinafter “Order No. 889”]. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp>
4. *Regional Transmission Organizations*. Final Rule, 89 FERC ¶ 61,285, 65 Fed. Reg. 809, at pp. 828-29 (1999) [hereinafter “Order No. 2000”].
5. In practice, ISOs and RTOs perform the same role in their respective geographic areas.
6. “The Future of the Electric Grid.” Massachusetts Institute of Technology Energy Initiative. (2011): 5. http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf
7. “The Future of the Electric Grid.” Massachusetts Institute of Technology Energy Initiative. 4.
8. *NERC Compliance Registry List Summary*. North American Electric Reliability Corporation. (2012): 2. http://www.nerc.com/files/NERC_Compliance_Registry_Matrix_Summary20121231.pdf
9. “Western Interconnection Balancing Authorities.” Western Electricity Coordinating Council. 2012. http://www.wecc.biz/library/WECC%20Documents/Publications/WECC_BA_Map.pdf. Three of these balancing authorities are international and thus not registered with NERC. Another two (PACW and PACE) are registered as a single balancing authority with NERC. The WECC total also includes a new balancing authority that will go live in 2013 and has not yet registered with NERC.
10. “2011 Long Term Reliability Assessment.” North American Electric Reliability Corporation. 8.
11. “State Electricity Profiles 2010,” U.S. Energy Information Administration. 2012. <http://www.eia.gov/electricity/state/pdf/sep2010.pdf>
12. *Ibid.*
13. *Ibid.*
14. *Ibid.*
15. *Integration of Variable Energy Resources*. Final Rule, 139 FERC ¶ 61,246, at P 1 & n.1 (2012) [hereinafter “Order No. 764”]. Available at <http://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf>
16. These policies have historically been motivated by a number of rationales, including the development of new clean energy industries, promoting greater energy diversity, and reducing CO₂ and other air emissions.
17. “Renewable Portfolio Standard Policies.” Database of State Incentives for Renewables & Efficiency. 2012. http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf
18. Total electricity generation capacity is approximately 1050 GW. “Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State.” U.S. Dept. of Energy, Energy Information Administration. Last modified October 2012. <http://www.eia.gov/electricity/data/state/>
19. “2012 Long Term Reliability Assessment.” North American Electric Reliability Corporation. 28.
20. See, e.g., Order No. 764 (requiring jurisdictional transmission providers to offer intra-hourly transmission scheduling to better accommodate the variability of renewable generators, and to amend their interconnection agreements to require new renewable generators to supply meteorological information to allow projections of power production).
21. FERC recently addressed a complaint filed by wind generators concerning BPA’s practice of curtailing transmission for wind generators when environmental constraints and river conditions required high levels of hydropower generation. *Iberdrola Renewables, Inc. v. Bonneville Power Admin.* Order Granting Petition, 137 FERC ¶ 61,185 (2011). FERC agreed with the renewable generators that BPA’s practice was unduly discriminatory, and required the agency to revise its transmission tariff to ensure that renewable generators are offered service comparable to that offered to other users. *Ibid.* at P 78.
22. *Integration of Variable Energy Resources*. Notice of Proposed Rulemaking, 133 FERC ¶ 61,149, at P 11 (2010).
23. Yeomans, Wes. “Integrating Renewables Into the Grid: Tariff and Market Issues.” Presentation to a Joint Session of the Staff Subcommittees on Electricity and Electric Reliability – NARUC Winter Meetings. Washington, DC. February 14, 2010. <http://www.narucmeetings.org/Presentations/Yeomans%20NARUC%20Staff%20Sub%20Feb%202014%202010.pdf>
24. From 1980 to 2006, coal was the largest single source of fuel in the U.S. electricity fuel mix, comprising at least 50 percent of the annual net electricity generation. While coal remains the most used fuel for electricity generation, it now comprises just 38 percent of net generation. “Annual Energy Review.” U.S. Dept. of Energy, Energy Information Administration. (2011): 224. http://www.eia.gov/totalenergy/data/annual/pdf/sec8_8.pdf
25. “Coal Plant Retirements: A Statistical Update... It’s Happening Everywhere.” Credit Suisse Equity Research. March 19, 2012.
26. “Coal Fleet Announcements.” Edison Electric Institute. 2012.
27. This estimate comes from BPC’s Policy Case scenario, which reflects the current market conditions and regulatory landscape as of July 2012. Many assumptions were based on the EIA’s Annual Energy Outlook (EIA AEO 2012 Early Release) with other assumptions made by BPC. This modeling scenario incorporates existing finalized federal and state regulations as of summer 2011 in addition to the Mercury and Air Toxics Standards (MATS) and the Cross-State of Air Pollution Rule (CSAPR). Since BPC’s analysis, CSAPR was vacated by the D.C. Circuit Court in August 2012. In the absence of CSAPR, the Clean Air Interstate Rule (CAIR) remains in place. Macedonia, Jennifer, and Colleen Kelly. “Projected Impact of Changing Conditions in the Power Sector.” (2012): 7-9. <http://bipartisanpolicy.org/sites/default/files/Electric%20Power%20Sector.pdf>.
28. “Natural Gas Weekly Update.” U.S. Dept. of Energy, Energy Information Administration. Last modified September 27, 2012. <http://www.eia.gov/naturalgas/weekly/>
29. Gas prices at Henry Hub estimated to hit \$5.02/mmBTU in 2026. *Annual Energy Outlook 2013: Early Release*. U.S. Dept. of Energy, Energy Information Administration. Last modified December 5, 2012. <http://www.eia.gov/oiaf/aeo/tablebrowser/>
30. *Ibid.* Average minemouth coal price (in 2011 dollars per short ton) is expected

- to increase from \$36.37 per short ton in 2010 to \$49.26 per short ton in 2020.
31. State regulations targeting carbon dioxide or other air pollutants, as well as state RPS requirements, may also contribute to coal plant retirements, but are not expected to be a significant driver.
 32. For general background, see “Mercury and Air Toxics Standards (MATS).” Environmental Protection Agency. 2012. <http://www.epa.gov/mats/>
 33. For general background, see “Cross-State Air Pollution Rule (CSAPR).” Environmental Protection Agency. 2012. <http://www.epa.gov/airtransport/>
 34. *EME Homer City Generation, L.P. v. Env'tl. Prot. Agency*, 696 F.3d 7 (D.C. Cir. 2012).
 35. Two additional EPA regulations affecting the power sector, which will address coal ash disposal and cooling water intake systems, were not found to substantially impact projections of coal plant retirements in BPC's analysis. Macedonia, Jennifer et al., “Environmental Regulation and Electric System Reliability,” (2011): 21-23, <http://bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf>
 36. Electricity demand growth was calculated from 2010 to 2025. In addition to economic pressure, low electricity demand growth can also be attributed to state and federal energy efficiency programs. “Electricity Supply, Disposition, Prices, and Emissions, Reference Case.” *Annual Energy Outlook 2013: Early Release*. U.S. Dept. of Energy, Energy Information Administration. www.eia.gov/forecasts/aeo/er/
 37. BPC staff calculation using *EIA Annual Outlook* data. <http://www.eia.gov/forecasts/aeo/er/index.cfm>
 38. Of the 40 MW of new power plant infrastructure in the development pipeline, 22.4 GW is new natural gas-fired capacity. Tierney, Susan F. “The Positive Outlook for Cleaner Air and Reliable Electric Service: Executive Summary and Report with Appendix.” (2012): 11. http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Tierney_PositiveOutlook_MATSReliability_June_2012.pdf
 39. In addition, while most new gas-fired capacity will likely be constructed near major load centers and existing transmission infrastructure, in some cases connecting new gas-fired capacity to load may require new transmission investments.
 40. Williams, Christina. “PacifiCorp Report: Wind Integration Getting Cheaper.” Nov. 29, 2012. <http://www.sustainablebusinessoregon.com/index.php/articles/2012/11/pacifiCorp-report-wind-integration.html>. PacifiCorp has noted that low natural gas prices have significantly reduced the costs of reserves, from \$9.70 per MWh in 2010, to \$1.89 per MWh.
 41. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) [hereinafter “EPA Act 2005”], § 1241, Transmission Infrastructure Investment (adding § 219 to the Federal Power Act, 16 U.S.C. § 824s); § 1221, Siting of Interstate Electric Transmission Facilities (adding § 216 to the Federal Power Act, 16 U.S.C. § 824p).
 42. EEI is projecting that transmission investment in 2013 and 2014 will be lower than in 2012 because of the poor economy and the recent completion and/or delay of major transmission projects. “Transmission Projects: At a Glance.” Edison Electric Institute. (2012): ix. http://www.eei.org/ourissues/Electricity-Transmission/Documents/Trans_Project_lowres.pdf
 43. Transmission investment appears to be increasing at the federal level as well. For example, Tennessee Valley Authority planned construction expenditures on transmission is expected to grow from \$256 million in 2012 to \$428 million in 2015. “Tennessee Valley Authority Form 10-K 2012.” U.S. Securities and Exchange Commission. <http://www.sec.gov/Archives/edgar/data/1376986/000137698612000043/tve-09302012x10k.htm>
 44. “2012 Long-Term Reliability Assessment.” North American Electric Reliability Corporation. 39.
 45. “2010 Long-Term Reliability Assessment.” North American Electric Reliability Corporation. 2010. <http://www.nerc.com/files/2010%20LTRA.pdf>
 46. “2011 Long-Term Reliability Assessment.” North American Electric Reliability Corporation.
 47. “The Future of the Electric Grid.” Massachusetts Institute of Technology Energy Initiative. 78.
 48. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Final Rule, 136 FERC ¶ 61,051, at PP 1-2 (2011) [hereinafter “Order No. 1000”]. Available at <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf>
 49. “Recovery Act Interconnection Transmission Planning.” U.S. Dept. of Energy, Office of Electricity Delivery and Energy Reliability. <http://energy.gov/oe/information-center/recovery-act/recovery-act-interconnection-transmission-planning>
 50. *California Wilderness Coalition v. DOE*, 631 F.3d 1072 (9th Cir. 2011); *Piedmont Environmental Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).
 51. For example, nine federal agencies executed a memorandum of understanding promoting coordinated review of transmission projects. See *infra*, n.77 and accompanying text. In October of 2011, the administration established an inter-agency Rapid Response Team for Transmission (RRTT), the objective of which is to better integrate and coordinate federal and state consultation, permitting, and review procedures, and to improve the timeliness of these procedures. See *infra*, n.81-83 and accompanying text.
 52. For example, energy management systems enabled by advanced sensors and controllers can result in more efficient utilization of transmission assets, and improved grid resiliency to power system disturbances.
 53. Customers in some states have vocally objected to the installation of smart meters, citing perceived concerns over public health, meter inaccuracies, and privacy. Multiple studies including from the Vermont Department of Health, California Council on Science and Technology, Maine's Center for Disease Control, and Utilities Telecommunications Council have highlighted that smart meters do not cause adverse health effects; smart meters result in much smaller RF exposure levels than many common household electronic devices, including cell phones.
 54. These include the extensive outages experienced in the northeast during Superstorm Sandy in 2012, as well as weather-related outages in the northeast during an October 2011 snowstorm, outages in the southwest in September 2011 due to insufficient operating coordination, and cold weather-related outages in the southwest in February 2011. NERC and FERC have released a detailed report on each of the 2011 events. See <http://www.nerc.com/page.php?cid=5>
 55. LaCommare, Kristina Hamachi, and Joseph H. Ito. “Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.” (2006): 18. Available at <http://eetd.lbl.gov/ea/ems/reports/58164.pdf>. Costs are shown in U.S. 2002-CPI-weighted dollars.
 56. The nor'easter of October 2011 produced a heavy and unusually early snowfall across 10 northeastern U.S. states and Canada.
 57. “Report on Transmission Facility Outages During the Northeast Snowstorm of

- October 29-30, 2011.” Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. (2012): 8. <http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf>
58. “Frequently Asked Questions.” North American Electric Reliability Corporation. Last modified 2012. <http://www.nerc.com/page.php?cid=1%7C7%7C114>
 59. A key element of this assessment is an analysis of individual regions’ planning reserve margins, which measure the amount of generation capacity available to meet projected demand over the forecast horizon. Specifically, planning reserve margin is calculated as the difference in deliverable or prospective resources and net internal demand, divided by net internal demand. See “Reliability Indicators: Planning Reserve Margin.” North American Electric Reliability Corporation. <http://www.nerc.com/page.php?cid=4%7C331%7C373>. Planning reserve margins for each region are compared against the NERC reference reserve margin for each region to provide an indicator of potential resource adequacy challenges. In its most recent assessment, NERC identified forthcoming EPA regulations, variable energy resource integration, critical infrastructure protection, and interconnection-wide modeling and coordination as important emerging reliability issues. See “2011 Long-Term Reliability Assessment.” North American Electric Reliability Corporation.
 60. As permitted by statute, NERC has delegated certain of its authorities to eight regional reliability entities. Regional entities may propose their own regional reliability standards, and may also exercise enforcement authority within their own regions, subject to NERC and FERC oversight.
 61. “NERC Cost Effective Analysis Process (CEAP) for NERC ERO Standards – Draft.” North American Electric Reliability Corporation. 2012. http://www.nerc.com/docs/standards/sar/NERC_CEAP-5-4-12_SCPPostedVersion1.pdf
 62. Fisher, Emily, Joseph H. Eto, and Kristina Hamachi LaCommare. “Understanding Bulk Power Reliability: The Importance of Good Data and a Critical Review of Existing Sources.” Lawrence Berkeley National Laboratory. 2012. <http://www.escholarship.org/uc/item/7d41327x>
 63. “The Future of the Electric Grid.” Massachusetts Institute of Technology Energy Initiative. 79.
 64. See Order No. 1000 at P 79. Note that in regions with vertically integrated utilities, consideration of such alternatives has traditionally been a part of IRP processes.
 65. While distribution-level storage is not yet economic, potential opportunities include community energy storage with advanced batteries, control of electric vehicle charging rates, or operator control of appliances such as hot water heaters. These opportunities are being tested at small scales. AEP has included community energy storage as part of its GridSMART Demonstration Project in Ohio, which has been conducted with support from DOE. See http://www.smartgrid.gov/project/aep_ohio_gridsmartm_demonstration_project. Bonneville Power Authority has conducted pilot programs to store excess wind energy using residential hot water heaters in a number of districts. See <http://www.masonpud3.org/newsdisplay.aspx?newsid=758>
 66. Fleeman, J.A. et al. “EHV AC and HVDC Transmission Working Together to Integrate Power.” 2011. <https://efs.iowa.gov/filing/groups/external/documents/docket/085882.pdf>
 67. The costs of converters to link DC lines to the AC grid is high, such that the economics of HVDC become less favorable as more points of interconnection are added.
 68. *Plains & Eastern Clean Line, LLC*, Docket No. 10-041-U, at 10 (Ark. Pub. Serv. Comm’n Jan. 11, 2011). Arkansas Public Service Commission rejected an application from Plains and Eastern Clean Line for public utility status because the project would not serve customers in the state. Plains and Eastern Clean Line has since filed an application to DOE and the Southwestern Power Administration (SWPA) under section 1222 of EAct 2005 to partner with SWPA on the project, which would allow the company to use SWPA’s eminent domain authority to construct the line. See Beattie, Jeff. “Grid Firm Seeks Federal Eminent Domain Authority to Advance Power Lines.” *The Energy Daily*. August 23, 2012. <http://www.theenergydaily.com/power/8395.html>
 69. “State Strategies for Accelerating Transmission Development for Renewable Energy.” National Governors Association. (2012): 16. <http://www.nga.org/files/live/sites/NGA/files/pdf/1201ENERGYTRANSMISSIONWP.PDF>
 70. Berst, Jesse. “Federal Delays May Force NorthWestern to Abandon Transmission Project.” *Smart Grid News*. August 17, 2012. http://www.smartgridnews.com/artman/publish/Delivery_Transmission/Federal-delays-may-force-North-Western-to-abandon-transmission-project-5056.html. NorthWestern faced interrelated difficulties in generating sufficient customer interest in the capacity of the line. See NorthWestern Corporation, Form 10-Q, at p. 11 (Oct. 19, 2012) (explaining that BPA had elected not to pursue a subscription to the line, and that in light of continued market uncertainty and other factors, NorthWestern was discontinuing its efforts on the MSTI line).
 71. Among the criteria for consideration as a NIETC are transmission congestion, insufficient diversity of supply, and potential gains in energy independence, broader energy policy goals, or national security. See EAct 2005 § 1221(a) (adding § 216(a)(4) to the Federal Power Act, 16 U.S.C. § 824p(a)(4)).
 72. *California Wilderness Coalition v. DOE*, 631 F.3d 1072 (9th Cir. 2011). Also at issue has been the breadth of FERC’s backstop authority. FERC interpreted the statute as authorizing backstop siting where a state had explicitly denied a project application. *Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, Final Rule*, 71 Fed. Reg. 69,440, 69,444, FERC Stats. & Regs. ¶ 31,234 (Dec. 1, 2006). However, a 2009 decision by the Fourth Circuit Court of Appeals held that the backstop authority does not apply in cases where the state has explicitly denied a project application. *Piedmont Environmental Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).
 73. EAct 2005 § 1221(a) (adding section 216(i) to the Federal Power Act, 16 U.S.C. § 824p(i)).
 74. “Transmission Line Siting Compact.” National Center for Interstate Compacts. Last modified 2011. <http://www.csg.org/NCIC/TransmissionLineSitingCompact.aspx>
 75. EAct 2005, § 1221(a) (adding section 216(h) to the Federal Power Act, 16 U.S.C. § 824p(h)).
 76. Federal Power Act § 216(h)(3), codified at 16 U.S.C. § 824p(h)(3).
 77. “Regarding Coordination in Federal Agency Review of Electric Transmission Facilities on Federal Land.” Memorandum of Understanding between the U.S. Dept. of Agriculture, Dept. of Commerce, Dept. of Defense, Dept. of Energy, Environmental Protection Agency, the Council on Environmental Quality, the Federal Energy Regulatory Commission, the Advisory Council on Historic Preservation, and Dept. of the Interior. 2009. <http://www.achp.gov/docs/TransmissionMOU.pdf>
 78. *Ibid.* A III.
 79. “e-Trans Federal Permitting Transmission Tracking System.” U.S. Dept. of Energy. <http://trackingsystem.nisc-llc.com/etrans/utility/Search.seam>
 80. “Project Information.” SunZia Southwest Transmission Project. http://www.sunzia.net/project_information.php
 81. “Interagency Rapid Response Team for Transmission.” White House Council

- on Environmental Quality. Last modified Oct. 28, 2009. Accessed January 17, 2013. <http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission>. The participating agencies are the U.S. Dept. of Agriculture, Dept. of Commerce, Dept. of Defense, Dept. of Energy, Dept. of Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation, and the White House Council on Environmental Quality.
82. *Ibid.*
 83. "e-Trans Federal Permitting Transmission Tracking System." U.S. Dept. of Energy. <http://trackingsystem.nisc-llc.com/etrans/utility/Search.seam>
 84. While Order No. 1000 does not require merchant transmission developers to participate in regional planning processes, it does encourage them to do so. See Order No. 1000 at P 165. Merchant developers are required to submit information that allows public utility providers in the region to assess the reliability and operational impacts of the merchant developer's proposed project on other systems in the region. *Ibid.* P 164.
 85. Subsequently, the Dept. of Defense, the Environmental Protection Agency and the National Park Service also joined California's Renewable Energy Action Team. "What is DRECP?" Desert Renewable Energy Conservation Plan. Last modified July 10, 2012. <http://www.drecp.org/about/index.html>
 86. "Recommendations to Western Governors' Association: Transmission Process Siting Reforms." Keyes & Fox and Aspen Environmental Group. 2012. <http://www.westgov.org/wieb/meetings/boardsprg2012/briefing/04-27-12TransRecommend.pdf>
 87. Elliot, E. Donald. *Lessons from Implementing the 1990 CAA Amendments*. 40 *Envtl. L. Reporter* 10592 (2010). The paper describes the assignment of responsibility for rules necessary to implement the 1990 amendments to the Clean Air Act to particular EPA employees. *Ibid.* at 10593.
 88. For example, regional planning processes conducted by most RTOs consider projected generation and demand over a decade or more.
 89. In general, the costs of transmission projects that are undertaken for reliability purposes are spread broadly across the footprint of the ISO. See "The Future of the Electric Grid." Massachusetts Institute of Technology Energy Initiative. 88.
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 92. *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*. Interim Order on Reconsideration, Docket No. 33672. Nov. 6, 2007.
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 94. See *California Independent System Operator Corp.* 121 FERC ¶ 61,286 (2007) (approving the LCRI in concept). See also "Location Constrained Resource Interconnection." California Public Utilities Commission. Last modified Nov. 11, 2008. http://www.cpuc.ca.gov/PUC/energy/wholesale/02_planning/02_ire/lcri.htm
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 99. Order No. 1000 at P 641.
 100. See generally EPA Act 2005 §§ 1221, 1241. Order No. 1000. *Promoting Transmission Investment through Pricing Reform*. Final Rule, 116 FERC ¶ 61,057. 2006.
 101. Potential examples of distribution-level storage include community storage with advanced batteries, operator control of vehicle charging rates, and operator control of household appliances such as water heaters.
 102. Among the reasons for this is that the proliferation of smart grid technologies at the distribution level, which may create new points of entry for malicious actors. See Malashenko, Elizaveta, et al. "Cybersecurity and the Evolving Role of State Regulation: How it Impacts the California Public Utilities Commission California Public Utilities Commission." (2004): 2. <http://www.cpuc.ca.gov/NR/rdonlyres/D77BA276-E88A-4C82-AFD2-FC3D3C76A9FC/0/TheEvolvingRoleofStateRegulationinCybersecurity9252012FINAL.pdf>
 103. "The Future of the Electric Grid." Massachusetts Institute of Technology Energy Initiative. 178.
 104. "The Future of the Electric Grid." Massachusetts Institute of Technology Energy Initiative. 180.
 105. The blurring of transmission and distribution is a key theme in DOE's vision for the future of the U.S. electric grid, which aspires toward a system that is fully integrated from end-to-end. Azar, Lauren. "Visioning the 21st Century Electricity Industry: Strategies and Outcomes for America." Presentation given on February 8, 2012. http://www.smartgridnews.com/artman/uploads/1/DOE_Vision_2035_presentation_Feb_2012.pdf
 106. 16 U.S.C. § 824h(b) ("The Commission may confer with any State commission regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.").
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 108. FERC's jurisdiction does not extend to cooperatives and government-owned entities for most purposes.

109. *Preventing Undue Discrimination and Preference in Transmission Service*. Final Rule, FERC Stats. & Regs. ¶ 31,241, 72 Fed. Reg. 12,266 (Mar. 15, 2007). Utility transmission plans were required to be consistent with the following principles: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, and (7) economic planning studies, and include an explanation of how the utility will coordinate with other utilities in the region on transmission. *Ibid.* PP 84, 426.
110. Order No. 1000 at P 482 n.374.
111. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*. Order on Rehearing and Clarification, 139 FERC ¶ 61,132, at PP 502-03, 77 Fed. Reg. 105 (May 31, 2012).
112. Loop flows result because electricity seeks the path of lowest impedance as it flows through the transmission grid, without regard to either regional borders or to the “contract paths” that entities doing business on the grid have agreed to. Thus, the transmission of power along a particular, contracted path may create unintended flows along parallel transmission paths. This congestion diminishes the available transmission capacity on the parallel paths, imposing costs on the owner of that transmission path and on consumers. At the extreme, loop flows may approach the physical limitations of the transmission line, causing reliability problems.
113. “Recovery Act Interconnection Transmission Planning.” U.S. Dept. of Energy, Office of Electricity Delivery and Energy Reliability. <http://energy.gov/oe/information-center/recovery-act/recovery-act-interconnection-transmission-planning>.
114. See Order No. 1000 at P 148 (requiring that utilities must consider non-transmission alternatives on a comparable basis to new transmission facilities, in the regional planning process).
115. See Pub. Utilities Regulatory Policies Act §§ 111(d)(7), 111(d)(16), 16 U.S.C. §§ 2621(d)(7), 2621(d)(16). The latter provision was added by the Energy Independence and Security Act of 2007 § 532(a), Pub. L. No. 110-140, 121 Stat. 1492 (2007).
116. Wilson, Rachel, and Paul Peterson. “A Brief Survey of State Integrated Resource Planning Rules and Requirements.” Synapse Energy Economics, Inc. (2011): 13-16, http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf
117. See Order No. 1000 at P 214.
118. See Order No. 1000 at P 213.
119. Institutional changes such as sharing flexible reserves, dynamic schedule among BAs, universal intra-hour scheduling, and energy imbalance markets increase system flexibility.
120. Hamachi, LaCommare, and Ito. “Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.” (2006): 26. Costs are shown in U.S. 2002-CPI-weighted dollars.
121. Public Act. No. 97-616, 2011 Ill. Laws 616 (2011).
122. “The Future of the Electric Grid.” Massachusetts Institute of Technology Energy Initiative. 132-134.
123. *Assessment of Demand Response & Advanced Metering*. Federal Energy Regulatory Commission. (2012): 15. Available at <http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf>. FERC staff has issued such reports annually since 2006 as required by EPA Act 2005 § 1252(e)(3). We draw from several recent annual reports in this discussion. The 2012 report cited herein states that as of September 2011 approximately 10 million smart meters had been installed through ARRA funding, and that ultimately, ARRA will fund approximately 15.5 million smart meter(s). *Ibid.*
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