DOE EAC Electricity Adequacy Report
CHAPTER 4: Transmission Adequacy
October 31, 2008 DRAFT

A ROBUST INTERSTATE ELECTRIC TRANSMISSION NETWORK MUST BE DEVELOPED TO ENABLE OUR ELECTRICITY FUTURE

The existing interstate electric transmission network is the result of actions taken primarily by vertically integrated utilities to build generation and transmission to serve their customers' electricity demands, to provide for the wholesale purchase and sale of electricity with neighboring utilities, and to share generating capacity reserves to minimize installed capacity reserves. This system is now at an age and condition requiring significant replacement of original infrastructure and one that is not robust enough to enable the electricity future projected for the United States. Broad-scale regional and interregional planning and meeting larger national needs was not the goal in planning the current system. Yet this grid system is being called on to meet the needs of wholesale markets that have evolved since the passage of the Energy Policy Act of 1992, and more recently to integrate remote sources of renewable generation.

There are two main reasons why there is a critical need to upgrade our nation's electric transmission grid. First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, often remotely located, to customer load centers. According to Rick Sergel, president and CEO of the North American Electric Reliability Corporation (NERC), expedited transmission development is key to addressing both of these issues. "We need more transmission resources to maintain reliability and achieve environmental goals. Transmission lines are the critical link between new generation and customers, yet we continue to see transmission development lag behind generation additions. Faster siting, permitting, and construction of transmission resources will be vital to keeping the lights on in the coming years."[1]

Transmission planning and development must be done in the context of comprehensive demand and resource analysis, to ensure that demand-side resources and environmentally desirable supply-side resource options are fully considered and pursued. Add to this the likelihood of further demand growth due to increased electrification of the transportation sector and industrial processes as we pursue strategies to reduce society's impact on climate and the environment overall. The nation needs a broad vision for a transmission system that will help meet the goals of energy security, electricity adequacy, and environmental protection. Collaboration among the many various stakeholders will be necessary to make this vision a reality.

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

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[1] NERC (October 23, 2008). 2008 Long-Term Reliability Assessment. Press Release. http://www.nerc.com/news_pr.php?npr=186.

electricity bill today, typically less that 10%.[2] Even with cost of significant new and upgraded transmission, a properly planned and developed transmission system can facilitate lower overall costs for transmission dependent utilities (TDUs) and ultimately customers by creating better delivery efficiencies and greater market reach for energy supplies. The development of a more robust electricity transmission grid will certainly require more equipment, material and labor resources at a time when there is a growing global demand. While global market forces may create better supply in the long term, the availability of equipment, material, and labor may be limited and higher cost in the short term.

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

- Access to new generation technologies and the ability to share the benefits of demand response and smart grid initiatives across broad regions.
- Improved system resource adequacy, by allowing greater sharing of resources and less dependence on local generation and constrained fuel supplies.
- Enhanced system reliability, security, and efficiency.
- Increased market competition that will benefit customers by eliminating grid bottlenecks which inflate costs by blocking supply.
- Lower and more stable rates for consumers over the long term through increased access to lower cost resources and a more diverse portfolio of energy sources made accessible through transmission.
- Access to renewables and other low-carbon resources to meet RPS requirements and greenhouse gas (GHG) emission reduction goals.

Transmission Adequacy Recommendations:
DOE must focus on the following to develop a robust interstate electric transmission grid for our energy future with direct collaboration among many stakeholders.

- DOE should seek the development of comprehensive and long-term planning efforts, one for the Eastern U.S. interconnection grid and another for the Western U.S. interconnection grid.
    - These efforts should include full consideration of demand- and supply-side options, “technology neutral” analyses, adequate assessment of environmental impacts (including GHG emissions), full support for renewable development, robust planning horizons, and full consideration of electrification of transportation elements and industrial processes for our energy future.
- DOE should address siting issues by supporting FERC siting authority for transmission above 345 kV addressing bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources as recommended through regional and interconnection-wide planning efforts. The DOE must also take a strong lead federal role for expeditious siting of all transmission over federal land.

[2] http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf (p 131).

- DOE should encourage FERC to lead in the development of broad cost allocation for backbone interstate transmission facilities as these have broad benefits across interconnected grids.
- DOE should expand research into wide-area monitoring and control initiatives, network integration of renewable resources, and control center enhancements needed for grid security and our energy future. DOE and FERC should also support and encourage the research, development and deployment of new and innovative technology solutions for electricity transmission.
- DOE and FERC should support reduced barriers for transmission investors and new transmission ownership structures, while ensuring that reliability is not jeopardized.

1. BROADER INTERCONNECTION-WIDE PLANNING EFFORTS NEEDED

Developing a robust electricity transmission network that enables our electricity future requires longer-term regional (e.g., within states, regional transmission organization (RTO) areas or across multiple utilities), and interregional planning (e.g., within the Eastern or Western U.S. interconnected grids - see Figure 1). The exception is the Electric Reliability Council of Texas (ERCOT) interconnection, where interconnection-wide planning has been more progressive, facilitated by its location. Such planning must take into account not only traditional transmission planning issues, such as interconnection queues, estimating demand-side program impacts, regional seams issues, and "just in time" short-term transmission development, but also broader national goals.

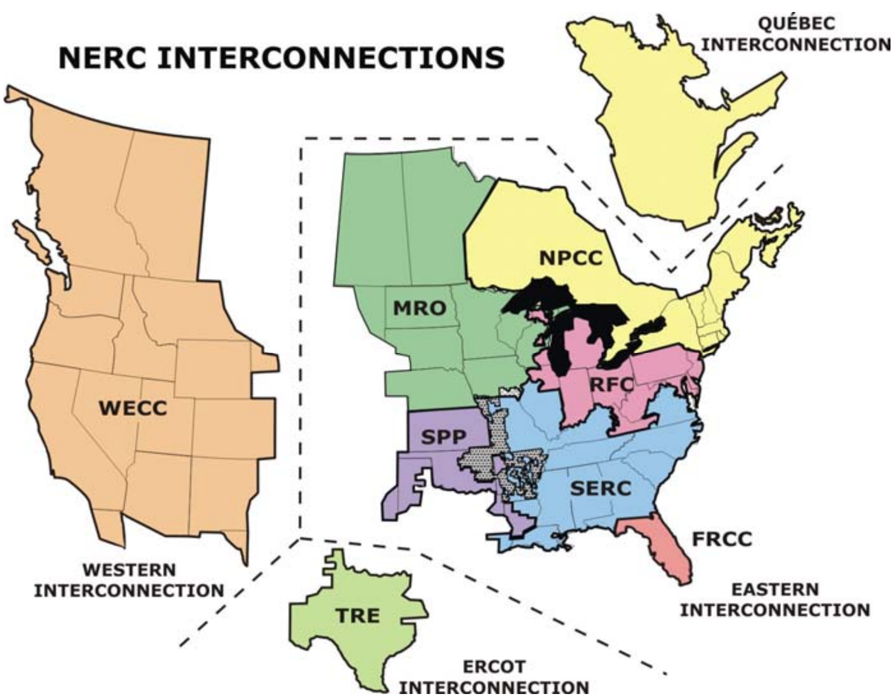

Figure 1: Map of NERC reliability regions.

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

Confounding the planners' extrapolations of future needs will be government's response to climate change. Compliance with applicable RPS standards, the trend toward electrified transportation, and overall pressure on industrial sectors to reduce GHG emissions could result in a tremendous additional demand on existing transmission infrastructure. Areas with high quality renewable energy resources, such as wind, solar, and geothermal energy, tend to be located at significant distances from population centers. This fact is highlighted in the DOE's 20% Wind Energy by 2030 report.[3] Accessing these resources and providing adequate capacity to facilitate new electrification initiatives will require expanded use of the transmission grid. Government at various levels, many utilities, and non-governmental organizations are also working to develop and deploy smart grid options. These and other demand-side and distributed generation options will help offset a portion of the growing electricity demand and further reduce GHG emissions, but will not obviate the need for significant new transmission.

Broadened planning efforts should allow for consideration of new technologies that maximize both cost benefits and system efficiencies while minimizing environmental impacts. For example, where appropriate, such efforts may encourage greater use of higher voltage or EHV (Extra-High Voltage; i.e., 345kV and higher voltage) transmission lines, including complementary HVDC (High Voltage Direct Current) connections for transferring the nation's available sources of renewable energy to load centers, particularly where need for the lines is well established, environmental impacts are significant, and corridors are limited. These high-capacity lines enable the most prudent use of scarce corridors, and can be effectively integrated to form a more efficient, expanded interstate transmission grid that will serve long-term needs.

Progressive planning efforts should also consider using advanced conductor materials and integrating more efficient equipment to minimize system losses and further reduce GHG emissions. The policy of planning the transmission system of tomorrow is not just about building more lines, but rather crafting a smarter, superior system. This approach may not be considered least-cost over short time horizons, but will provide significant benefits to consumers going forward. To ensure lower prices and a higher quality system for consumers, these broader planning efforts should consider environmental and cost-benefit analyses, including the effects of all cost-effective demand-side options.

[3]http://www.20percentwind.org.

Currently, interregional planning within the Eastern and Western U.S. interconnections is inadequate, but can be improved. For example, the "lake effect" phenomenon, a power flow problem around the eastern Great Lakes, has existed for decades. This was a contributor to the spreading of the 2003 blackout in the Eastern U.S., but has yet to be resolved. Certainly, system controls, procedures, and compliance with mandatory reliability standards were put in place to mitigate the effects, but relatively little coordinated transmission investment has been made. This area is comprised of three RTOs in the U.S. and an independent operator in Ontario, Canada. RTOs (and ISOs, independent system operators) are responsible for transmission planning within their respective footprints, but they are not adequately addressing transmission planning with other regions.

DOE must seek the establishment of long-term interconnection-wide planning efforts and models with broad stakeholder participation. Two comprehensive planning studies, encompassing the Eastern and Western U.S. interconnected grids, should be undertaken to develop high-level EHV transmission plans. These studies, tailored to each interconnection while supporting common national goals, will serve to provide consistency and harmonization among regional plans. However, this "top-down" approach must be paired with a "bottom-up" approach that takes into account local needs and issues. Many states have been very proactive in planning for their energy future, advancing well beyond national efforts. RTOs have also been proactive within their regions. DOE must link local and regional efforts with national priorities to ensure a robust transmission system that allows large fractions of the population increased access to the energy sources they need, including renewable resources. As stated in the conclusion of the Electricity Advisory Board's 2002 *Transmission Grid Solutions Report*, "The importance of working cooperatively on the federal and state level to improve our transmission infrastructure cannot be overstated."[4]

Fortunately, states and regional entities appear to recognize the need for broader planning. FERC Order No. 890 calls for all transmission providers to participate in open, transparent regional planning processes. In the Eastern U.S., the Joint Coordinated System Plan is currently examining transmission infrastructure build-out plans that will facilitate the integration of a large amount of wind energy.[5] The Midwestern Governors' Association in 2007 published a GHG reduction platform that calls for increased attention to transmission, and more recently the Upper Midwest Transmission Development Initiative was formed to identify wind generation resources and transmission infrastructure to support those resources in a cost-effective manner.[6][7] In the Western U.S., the DOE and the Western Governors Association (WGA) are leading the Western Renewable Energy Zone transmission planning process so that the Western Electricity Coordinating Council (WECC) can better identify and plan for renewable-related transmission needs.[8] In addition, efforts by the Transmission Expansion Policy Planning Committee (TEPPC)

[4] Transmission Grid Solutions Report. DOE Electricity Advisory Committee. September 2002.
[5] http://www.jcspstudy.org.
[6] http://www.midwesterngovernors.org/EnergyInitiatives.htm.
[7] http://www.governor.iowa.gov/news/2008/09/18_2.php.
[8] http://www.westgov.org/wga/initiatives/wrez/index.htm.

have aided regional planning by performing economic analyses and guiding transmission planning processes in the Western U.S.

Key Recommendations:

- DOE must seek the establishment of Eastern and Western interconnection-wide planning efforts that mitigate seams issues and incorporate broad stakeholder participation. Comprehensive planning studies, encompassing each of the Eastern and Western U.S. interconnections, should be undertaken to develop high-level backbone EHV transmission plans.
- DOE should identify "best practices" with regard to full consideration of demand- and supply-side options, "technology neutral" analyses, adequate assessment of environmental impacts (including GHG emissions), full support for the development of renewable and other preferred technology generation, robust planning horizons, full consideration of electrification of transportation elements and industrial processes for our energy future, and should widely distribute such "best practice" information to planning entities and governmental authorities.

2. SITING OF EHV TRANSMISSION FACILITIES MUST BE IMPROVED

The institutional arrangements for planning and permitting transmission were not established with the intention of developing interstate EHV transmission lines, facilitating access to remote renewable resources, or with proper consideration for crossing federal lands. Thus, no structure exists to support the planning and permitting of such facilities. Currently, state and federal agencies are responsible for siting and permitting transmission lines in their respective jurisdictions, and often multiple entities with varied processes are involved in the siting of EHV transmission projects.

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

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

One example of this issue is American Electric Power's Jacksons Ferry - Wyoming 765 kV transmission line which required 16 years to complete, with nearly 14 of those years and $50 million spent on siting activities. A portion of the siting problems that plagued the project were simply the function of an interstate effort and the non-integrated state permitting process of Virginia, West Virginia, and several federal agencies. Each set of rules and regulations was reasonable independently, but when the project was revised to comply with requirements in one jurisdiction, filings needed to be amended in each of the other jurisdictions, and the review time was extended. This mode of permitting proved time consuming, inefficient and costly for consumers.

The Energy Policy Act of 2005 recognized the impediments for interstate transmission development and sought to address them in two ways. First, it provided for FERC “backstop” siting authority within National Interest Electric Transmission Corridors (NIETCs). These have proven to be controversial, both too broad in the view of some and too narrow in the view of others. As NIETCs are based solely on congestion, the current designated corridors are limited in scope and do not take into consideration the specific needs of other areas of the country. Second, it calls for the DOE to act as lead agency for coordinating federal authorizations and environmental reviews for transmission. More than three years later, the DOE has published a proposed rulemaking regarding its lead agency designation. Comments on the proposal, however, indicate that it may be inadequate to the task.

While opinions of the recommended course of action vary, all members of the EAC agree that the status quo for transmission siting is not acceptable. DOE should address siting issues by supporting FERC siting authority for transmission above 345 kV addressing bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources as recommended through regional and interconnection-wide planning efforts. FERC must also adopt broad cost allocation for these facilities, as cost allocation disagreement can be used as a pretext to impede transmission siting. Finally, the DOE must take a strong lead federal role for expeditious siting of all transmission over federal land.

Some believe all transmission siting should be accomplished by adoption of the FERC siting rules and processes for interstate natural gas pipelines. Others believe that a “top-down” approach that expands beyond federal lands is unnecessary, and that multi-state collaboration and better coordination of federal agencies responsible for transmission line permitting will serve to remove most of the impediments. Society’s desire to have access to renewable resources may be the “bottom-up” approach needed to break the logjam assuming the process improvements noted. Federal intervention may be warranted for facilities 345 kV and below that are needed to support national priorities.

The key driver of policies in this area and others will be the development of a comprehensive national energy policy for our electricity future. Some states have succeeded in the implementation of energy policy and have expedited processes pursuant to that objective. A good example includes the success of the CREZ (Competitive Renewable Energy Zone) initiative within ERCOT. While it should be noted that ERCOT is unique in being a separate interconnection entirely within one state (none of the other contiguous 48 states is similarly situated), the CREZ effort represents the effectiveness of interconnection-wide planning for the development of EHV transmission. The nation as a whole lacks this clarity in policy.

Key Recommendations:

- DOE should address siting issues by supporting FERC siting authority for transmission above 345 kV addressing bulk power system reliability, significant congestion, or interconnection and integration of low-carbon resources as recommended through regional and interconnection-wide planning efforts. The DOE must also take a strong lead federal role for expeditious siting of all transmission over federal land.
- Federal intervention may be warranted for facilities 345 kV and below that are needed to support national priorities.

3. COST ALLOCATION & RECOVERY MUST BE MADE MORE CERTAIN

The difficulty in determining who pays for transmission that benefits many users across multiple jurisdictions, for a variety of purposes and over a long time period, is a serious obstacle to transmission development. The methodologies for allocating costs to consumers can have a profound effect on the justification and authorization of transmission projects. Where RTOs have authority, they often determine the cost allocation methodologies. In other regions this task is delegated to individual states or utilities. In these areas, the lack of regional cost allocation methodologies and agreements can complicate the planning and approval of interstate projects, thus creating a higher level of uncertainty and risk for investors. Moreover, a lack of cost-allocation mechanisms for projects that span multiple RTOs or RTO and non-RTO regions adds additional complication. Such risks create significant disincentives to project development, especially since the construction of large-scale projects can extend over a number of years with large capital investment.

High-voltage transmission projects involve the large-scale transport of electricity, usually across long distances where the higher voltage increases the transmission efficiency and decreases the amount of electricity otherwise unavoidably lost. Thus, the nature of high-voltage transmission generally means benefits are provided across wide areas not limited by jurisdictional boundaries. For these types of projects, it is difficult to determine particular beneficiaries over the life of the projects. In addition, benefits are often categorized into "reliability" or "economic" benefits, and the allocation methodologies frequently differ between these categories. However, interstate transmission projects generally serve multiple purposes with benefits that can vary over time and with changing system conditions. Attempting to assign costs for these types of projects to any particular group is often met with objection, causing delays. In some jurisdictions, transmission costs are shared across all load serving entities in the footprint based on load ratio share. In this way, major backbone infrastructure can be planned based on the needs of the entire region. This promotes projects designed for maximum benefits to multiple stakeholders, minimizes the cost impact to any individual customer group, and avoids disagreements that occur under “beneficiary pays” or “participant funding” approaches.

RTOs as well as state and federal policy makers should encourage broad cost allocation for backbone transmission facilities approved by the interconnection-wide planning processes and other regional entities. This approach will support the development of transmission projects with widespread benefits. At the consumer level, sharing costs as broadly as possible reduces the rate impact while enabling the infrastructure that that will reduce congestion and lower delivered energy costs. A study conducted by CRA International, for example, estimates that a $2.7-3.5 billion investment in the western portion of the Southwest Power Pool (SPP) for 1,200 miles of 765 kV transmission (first two loops of the proposed SPP EHV Overlay) would result in an annual net benefit to the SPP region of $628-728 million, not including the added benefits of economic development and reduced CO_2 emissions. This means the cost of the transmission would be fully offset within five years. This portion of the plan also enables the development of 14 GW of wind generation in the region. This demonstrates how regional transmission development can benefit the region with stabilized electricity costs and encourage renewable energy development.[9]

Without clear cost allocation policies, developing large scale transmission projects is virtually impossible. In cases where a potential line crosses dissimilar cost allocation areas or RTOs, the project may be delayed to reconcile the cost allocation methodologies and determine who pays. Cost allocation disagreement can also impact transmission siting; therefore resolution of these two issues must be linked. Indeed, EAC members believe that cost allocation is the single largest impediment to any transmission development, especially across multiple RTOs or across RTO and non-RTO regions.

In addition to cost allocation, uncertainty with respect to cost recovery has a profound effect on decisions to build large scale high-voltage transmission. Timely recovery of transmission investment is a vital component in attracting sufficient investment, particularly for projects with timelines that extend multiple years. Since FERC issued its transmission incentive rule (Order No. 679), a number of transmission projects have been proposed. However, for transmission builders other than independent transmission companies where rates are entirely FERC-regulated, recovery of FERC-approved transmission costs can be challenged at the state level.

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

[9]http://www.spp.org/publications/ETA_OGE_WESTAR_Preliminary_Cost_Benefit_Analysis%20_from_CRA.pdf.

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

Key Recommendations:

- DOE should advise FERC to engage RTOs, transmission providers in non-RTO areas, and state and federal policy makers, to develop broad cost allocation methodologies for EHV transmission facilities approved by regional and interconnection-wide planning authorities.
- DOE should also advise FERC to continue promoting the use of formula rates and work with states to develop a middle-ground between certainty of investment return and cost-accountability.
- DOE and FERC should aid the industry in informing regulators and consumers on the need for transmission to stabilize electricity costs by providing supporting information through broad cost-benefit analyses.

4. GRID OPERATIONS AND MANAGEMENT SHOULD BE ENHANCED

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

Optimization of renewable resources in concert with the operation of the grid is needed. Historically, dispatching of resources was dependent on demand and the most cost effective generating plants that were nearby. Today, however, dispatching of resources is often limited by congestion, weather (for renewable energy) and other factors. Much higher renewable resource penetration will require an efficient and responsive fleet of traditional resources, new energy storage devices, and demand response resources to fill the gaps created by the inherent variability of renewable resources. Potential operating restrictions on the existing traditional generation fleet to achieve air or water quality improvements may impact the viability of those resources to help integrate renewables, and could lead to complex operational issues. In addition, the growing complexities and higher use of the grid, the long distances to renewable energy resources, and the continued addition of power electronics and computers needed to control the grid will be even more operationally challenging than today.

Better wide area monitoring and controls are needed for the grid. Much of the capability of the existing grid is a result of well-engineered controls and communication systems. Without them, the ability of the grid to reliably transfer significant amounts of power would be much diminished. However, NERC has determined that protection and control misoperations cause a growing percentage of bulk transmission outages.[10] More sophisticated detection and precise control action is needed. This includes situational awareness for the people operating the system to determine the correct automatic control actions and their timing. This can be facilitated by accelerating the work underway on precise time synchronized measurements on an interconnection-wide basis, also known as the North American SynchroPhasor Initiative (NASPI).[11] These phasor measurement units (PMUs) are often described as “diagnostic MRI” for the electric grid.

Today’s grid is operated in a manner that is not unlike driving down the interstate at 65 mph while opening and quickly closing your eyes every few seconds. This is enabled by today’s supervisory control and data acquisition systems or SCADA. PMUs offer the driver the “eyes wide open” advantage while driving down the interstate. PMUs need work, but the concept should be further developed to provide automatic control of a modern grid by quickly adapting the power system to serious loss of transmission, generation or load. The benefits are better reliability and greater capability of the grid to move power, as well as possibly preventing or mitigating the effects of a widespread blackout.

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

Changing the grid operations picture is the concept of smart grid, which enables demand response and other resources to be dispatched as generators are dispatched today. Plug-in hybrid electric vehicles (PHEVs) attached to the grid using smart grid technology also have significant potential to provide demand-side flexibility in the future, although the penetration of PHEVs would also increase overall electric load. Other energy storage technologies may also become cost-effective sources of system flexibility in the future.

New products and services could allow more efficient use of existing transmission infrastructure. The U.S. electric grid is highly congested in some areas. As the location of transmission congestion changes depending on outage conditions, seasonal variation, and other factors, opportunities exist for transmission customers to use spare transmission capacity during

[10] NERC 2008 Long-Term Reliability Assessment. http://www.nerc.com/files/LTRA2008.pdf.
[11] http://www.naspi.org.

uncongested periods. Recent FERC rules put in place conditional firm transmission and generation redispatch services to address unanticipated transmission constraints. It is also possible to dynamically rate transmission lines for ambient weather conditions, allowing more electricity to be transmitted over the line when temperatures are lower than at peak summer days. However, this will require transmission operators to know more about the system than is generally the case today. Making such options available to transmission customers, including variable output renewable energy generation sources, can allow more efficient use of the existing infrastructure and significantly reduce the cost of reliably integrating new generation into the grid.

Other devices can also help in the controllability of the grid. For example, flexible AC transmission systems (FACTS) can provide control and voltage support to improve grid reliability and throughput. In addition, the use of HVDC to complement the EHV AC network we have today can also be used to control the network, provide additional interregional connectivity to improve grid stability, and mitigate the spread of blackouts.

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

Key Recommendations:

- DOE should expand research into: (i) wide-area monitoring and control initiatives, (ii) network integration of renewable resources, and (iii) control center enhancements needed for grid security and our energy future.
- DOE should investigate technology to improve integration of variable resources and further the benefits of smart grid technologies and demand response, while taking steps to ensure the grid remains secure in all aspects, including cyber security.
- DOE and FERC should encourage development of tools for improved generation dispatch and system flexibility for our grid and energy future.
- DOE should ensure implementation of on-going recommendations from the 2003 blackout report and direct actions if not implemented successfully.

5. TECHNOLOGICAL INNOVATION SHOULD BE ENCOURAGED

In transmission, R&D efforts are needed in five broad areas: (i) achieving more effective use of existing rights-of-way, (ii) application of improved controls and diagnostics for the increasing complexity for our energy future, (iii) enhancing asset reliability and flexibility with lower life-time costs, (iv) reducing environmental and climate change impacts, and (v) advancing smart grid concepts to facilitate a self-healing grid and demand response options. Costs and risks to develop and implement a new technology can be substantial. FERC has encouraged development of advanced technology through incentives under the Energy Policy Act of 2005 to recognize these risks and reward "first adopters." However, not enough has been done to reward investment in new technology, particularly potentially beneficial technologies that may not be considered cost-effective in the near-term, by ensuring recovery of those investments.

As aging transmission facilities are upgraded and replaced, and as new facilities are designed and built, pursuing the R&D efforts listed above will support application of technology solutions that maximize the capability and reliability of the transmission network while minimizing investment in unnecessary infrastructure and reducing environmental impacts. But R&D leadership is needed. The industry is highly fragmented with over 500 transmission owners and over 3,000 distribution owners with R&D expenditures totaling less than 1% of revenues.

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

Key Recommendations:

- DOE should formulate an R&D roadmap, build an R&D portfolio, provide seed funding, and engage willing participants in joint efforts to develop and/or demonstrate new technologies.
- DOE should increase federal funding for transmission R&D and provide leadership at the federal level. Participation by national labs should also be increased.
- DOE should encourage FERC to support continued incentives for beneficial technology development and encourage state regulatory bodies to support cost recovery of appropriate transmission R&D investment.
- DOE should collaborate with EPRI and other private and public organizations to leverage R&D resources.

6. BARRIERS TO FINANCING AND CONSTRUCTION OF TRANSMISSION SHOULD BE LOWERED

Perhaps more so than at any point in the electric industry's history, new entrants stand poised to have a significant impact on the country's transmission infrastructure. While there have been less than a dozen new regulated utilities formed over the past 40 years, interest in the transmission sector is exceptionally high. In addition, a number of companies are exploring opportunities in the merchant transmission business. Most of these potential new entrants are drawn to the electric delivery business because of obvious need for capital and the fact that a “21st Century Grid” will require new thinking, new technologies, and new business approaches, which help level the playing field with traditional utilities and provide multiple opportunities for growth.

In recent years, tens of billions of dollars of equity have been raised by infrastructure funds looking for opportunities to deploy their capital in regulated or unregulated projects. These new players have lower return expectations than traditional private equity funds, and their time horizons for holding investments may be longer. In addition, commercial and investment banks have favored lending to utility projects, as they provide greater cash flow certainty during a period of economic unease.

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

A broader universe of entities should be encouraged to invest in transmission facilities, through vehicles such as joint ownership. When ownership and investment is shared, risks associated with large capital investments are reduced. Such arrangements might also reduce difficulties in accessing capital for large transmission projects, which could well be adversely affected in the next few years by the current economic downturn. Facilitating investments in transmission projects by a variety of entities with different business models (e.g., publicly- and cooperatively-owned, as well as shareholder-owned) can also dispel impressions that utilities are proposing such major transmission additions solely or largely to increase their rate bases and enhance shareholder profits.[12]

Today most incumbent electric utilities have the right of first refusal to construct, or arrange for construction of, any transmission project within their service territory. Reliability projects are generally completed expeditiously because they are required to meet NERC reliability standards. Concerns frequently are expressed by TDUs and consumer advocates that incumbent utilities can continue to exercise transmission and/or generation market power by delaying “economic” projects through the request for repeated feasibility and cost-benefit studies and other delaying tactics. Some TDUs have also expressed interest in participating jointly with incumbent utilities and other transmission owners in new transmission projects or significant upgrades, contributing their own capital, but those expressions of interest in many cases have not been reciprocated. States and RTOs should be encouraged to develop expedited timelines whereby utilities must commit to either constructing or contracting for the construction of economic projects and beginning construction of approved projects that will benefit consumers.

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[12] One example of such joint transmission development and ownership is the Cap X 2020 project in the Upper Midwestern United States. http://www.capx2020.com.

Coordinating transmission projects across the seams between RTOs and utility control areas is increasingly important to bring renewable energy to customer loads, as well as to improve overall grid robustness and the acquisition of lower cost electricity. Often, however, there is no mechanism for approval, cost allocation, and/or selection of owners for projects that cross these seams. FERC and RTOs should be encouraged to develop processes for dealing with these types of projects and facilitate independent transmission company participation and utility partnerships in "bidding" for construction rights. In addition, several states have created transmission authorities to stimulate the construction of high voltage transmission lines (e.g., Wyoming, Kansas).[13][14]

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

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

Key Recommendations:

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

[13] http://www.wyia.org.
[14] http://www.kansas.gov/keta.